CLEAN ENERGY SYSTEMS

The Power to Reverse Climate Change

5-March-2021

David Albright
Manager, Groundwater Protection Section
U.S. Environmental Protection Agency, Region IX
75 Hawthorne Street
San Francisco, California 94105

RE: Response to Technical Evaluation Comments and Information Request of CES's Responses to EPA's Initial Technical Evaluation Comments and Information Requests #1-4 CES-Mendota Site Underground Injection Control (UIC) Permit Application Class VI Pre-Construction Permit Application No. R9UIC-CA6-FY20-1

Dear Mr. Albright,

Clean Energy Systems, Inc. (CES) thanks you and the staff at the United States Environmental Protection Agency (EPA) for your continued review of our Class VI Pre-Construction Underground Injection Control (UIC) Permit Application for the Mendota site.

We have received your latest Technical Evaluation Comments and Information Request, dated 05-February-2021. The following five Enclosures seek to provide the additional information and clarifications requested. For completeness, we directly responded to EPA's Follow-up Questions/Requests within each Enclosure, shown in ***purple font***. If EPA deemed a previous response acceptable, no additional comments were made. CES worked with technical experts at Schlumberger to develop the responses.

In addition to Enclosures 1 through 5, we have included two Appendices. In support of our responses in Enclosure 4, Appendix A includes Updated Well Schematics. In relation to Enclosure 2, per your advisement, we downloaded EPA's updated Emergency and Remedial Response Plan (ERRP) template from the GSDT. Appendix B is an updated version of the Project's ERRP (revision number 1.2, dated 4-March-2021) to include the recommended information from the risk register.

Based upon EPA's feedback, CES understands and agrees the defined changes are to be made to the subject permit application material and resubmitted to EPA as a complete, updated package. CES will develop and provide EPA with an estimated submission schedule in the coming weeks.

If you have any questions related to the content of this response or wish to discuss these matters further, I can be reached via email at rhollis@cleanenergysystems.com.

We thank you for the productive dialogue regarding our Class VI UIC permit application to date and wish to continue discussions as we work to resolve a few remaining open items. I will reach out to you in the coming weeks with meeting and/or information requests on the pending topics.

Sincerely,

Rebecca M. Hollis
CES Director of Business Development – CNE

Enclosures

CC (via email): Keith Pronske, CES President & CEO
Natalie Nowiski, Schlumberger NE CCS BD and Legal Counsel
Vivian Rohrback, Schlumberger SIS Project Manager

ENCLOSURE 1

Evaluation of Applicant Responses to EPA's Technical Review Comments on the Geologic Information in the CES-Mendota Class VI Permit Application

EPA reviewed responses provided by Clean Energy Systems (CES) to EPA's questions about the CES-Mendota Class VI UIC Permit. EPA's Technical Review Comments and recommendations (dated August 9, 2020) are in blue text. CES's responses (dated September 30, 2020) are provided in green text. EPA evaluations are provided in red text. EPA expects that these questions can be answered based on available information and requests that they be addressed in the updated permit application that CES plans to submit later in 2021. Note that CES provided an Appendix containing several figures, some of which are marked as confidential business information: none of those figures are replicated in this document.

1 Additional Information on Formation Use and Supplemental Figures

Clean Energy would like to further clarify the regional geology and formation use at the Mendota site. The below section and figures are meant to give additional context or replace figures previously submitted. These figures will be incorporated into the final version of the narrative after all feedback is received from the EPA. Table 1 below summarizes the primary formations of interest at the Mendota Site and how they are intended to be used for this project. Table 2 summarizes inconstancies that the EPA identified for which specific questions were not asked.

Table 1:Formation description and intended use.

Primary Formations ofInterest	Formation Description and Intended Use
Garzas Sandstone	The Garzas sandstone member of the Moreno formation represents a major deltaic complex and overlies the Moreno Shale. This zone will be monitored for above confining zone migration of CO_2.
Moreno Shale (Well Correlation includes Ragged Valley Silt) Secondary Confining Zone	The Moreno shale is an organic rich marine shale. Because of the Moreno Shale's thickness (~1100ft) and because it is regionally extensive, it is intended to provide a seal to ultimately contain any injected CO_2 that may be migrating up from the below First Panoche sandstone.
First Panoche Sandstone Secondary CO_2 Injection Zone (Permission to inject into this formation is requested)	The First Panoche is intended to be a secondary injection zone to be used if the Second Panoche below is unsuitable for injection or if there is CO_2 migration which passes up through the below First Panoche Shale.
First Panoche Shale Primary Confining Zone	The First Panoche Shale is intended to be the primary confining zone that will vertically contain most or possibly all the injected CO_2. Because it is relatively thin (127 feet) and because its lateral continuity is unproven, this formation is not being relied upon to contain all the injected CO_2. Currently, this formation is interpreted to be continuous within the model domain.

Second Panoche Sandstone Primary CO_2 Injection Formation (Permission to inject into this formation is requested)	The Second Panoche sandstones are the primary target for CO_2 injection.
Third Panoche Potential CO_2 Injection Zone (Permission to inject into this formation is requested)	Although not the target of this project currently, this member may have potential in the future for CO_2 injection. The lower permeability of this member will likely make this a lower confining zone.
Third Panoche Shale Lower Confining Zone	The shales of the Third Panoche are intended to act as the lowermost confining zone.
Fourth Panoche Potential CO_2 Injection Zone	Although not the target of this project currently, this sandstone may have potential in the future for CO_2 Injection.

Table 2: Summary of inconsistences addressed.

Summary of Inconsistences Addressed		
Section	**EPA Inconsistency in Black Text**	**CES Clarification**
2 Regional Geology and Geologic Structure	"Core samples are available from 1 well (NAPA AVE A/1, about 3 mi to the east) ..."	*NAPA AVE A/1 is approximately 8.3 miles to the east.*
4 Depth, Areal Extent, and Thickness of the Injection and Confining Zones	"The primary confining layer is the Moreno Shale, ..."	*The primary confining layer is the First Panoche Shale. The Moreno is the secondary seal that will ultimately contain the CO_2.*
5 Hydrologic and Hydrogeologic Information	"..and so the water well summary in that document does not agree with the application narrative (Section 5.1.1 of Attachment B)"	*A large search radius (2.5 miles) for water wells was used to better understand the local hydrogeology, groundwater flow directions, and water use.*
6.1 Characteristics of Injection Zone Formation Water	"The table does not indicate which Panoche Sand the value represents, and the depth is shallower than the target formation at the Mendota site"	*This public data source did not specify which Panoche sandstone the sample was taken from, and this was the nearest data point available.*
6.1 Characteristics of Injection Zone Formation Water	"CES anticipates a salinity of about 25,000 mg/L at the Mendota site, although it is not stated what this is based on other than possibly a general increase in salinity moving westward."	*With deeper Panoche sandstones to the west at Mendota, it is expected that the salinity will be higher. The higher salinities were calculated using the resistivity logs of five wells near the Mendota site. This was discussed in Section 2.7.1.*
6.2 Mineral Composition of The Injection Zone	"However, Table 7 does not specify which Panoche sand layers the data represents."	*Table 7 represents mineralogy data likely from the Fourth Panoche sand at B.B Co 1.*
10 Facies Changes in the Injection or Confining Zones	"The description of the lithology from the B.B. Co 1 well is at a depth corresponding to the Fourth Panoche Sand. Figure 5 in the application narrative, however, shows the Second Panoche Sand as the primary injection formation, with the Fourth Panoche Sand as an optional formation."	*Ideally, core data from the Second Panoche are desired; however, only the B.B. Co 1 core was available for the Fourth Panoche.*
11 Structure of the Injection and Confining Zones	"Future cross sections should show an aerial view with transects labeled."	*The final update of the narrative will include labeled transects.*
13 Confining Zone Integrity	"The current porosity and permeability estimates for the Moreno Shale are 8% porosity and 4.7 mD for permeability (Table 3). The porosity appears low and the permeability appears somewhat high for a shale."	*These values may be higher than expected; however, this estimate lacks core data calibration in the Moreno Shale.*

EPA Evaluation of Response: Response is acceptable. Edits should be incorporated into the revised version of the permit application.

1.1 Update to Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

The Mendota site is located in the central San Joaquin Basin in Fresno County, California. The San Joaquin Basin formed as a forearc basin between the subducting Farallon plate in the west and the Sierra Nevada volcanic arc to the east, accumulating 25,000 ft of sediment overlying basement rocks capturing the last 100 million years of sedimentary and tectonic history. The San Joaquin Basin forms the southern half of California's Great Valley and is a major petroleum province.

The proposed Mendota_INJ_1 site is situated approximately 10 miles east of the late Cretaceous axis of the San Joaquin Basin, between Gill Ranch (GR), closer to the eastern edge of the basin, and Cheney Ranch (CR) gas fields, just west of the ancient basin axis, 6.5 miles NE and 11.7 miles SW of the projected well, respectively (Figure 1). Historical gas production at Gill Ranch targeted Late Cretaceous sandstones in a low amplitude structural closure, <100 ft, bounded by faults interpreted as high-angle reverse faults oriented NW-SE. Currently, the Gill Ranch field is being used for gas storage operations exploiting the properties of the reservoir sandstones. One inconsistency in the region is the depositional setting and naming convention of the sandstones at the Gill Ranch field and at the Mendota injection site. Mapping depositional settings in this basin is challenging because of the varying interpretations of stratigraphic classifications over time, the changes in sea level through time, and the evolving tectonic settings from forearc margin to strike-slip (Hosford Scheirer & Magoon, 2007).

Regional studies across the San Joaquin basin show a Cretaceous shelf edge subparallel to the NW- SE orientation of the basin axis just west of the Gill Ranch Field (Figure 1) (Hosford Scheirer & Magoon, 2007). *West of the shelf-edge margin is an interpreted slope with expected channel and fan deposits (Figure 2a). The position of the Gill Ranch field on the Cretaceous shelf suggests that its reservoir sandstones are deltaic: these are referred to in multiple publications as the Starkey sandstones. However, Panoche has also been used to describe the Cretaceous sandstones at Gill Ranch in published reports and in well records. Deltaic Starkey Formations on the shelf edge prograde into channel and fan deposits downdip into the Lathrop sandstone and Forbes , which have been described also within the Cretaceous Panoche Formation; the Starkey Formation is coeval to these downdip formations on the slope. The reference to the shelf and slope sandstones as Panoche in multiple publications and well reports contributes to the confusion. This is partly due to the attempt to correlate the subsurface stratigraphy with the Panoche Formation interpreted in outcrop. Based on Panoche as a naming convention for the slope and deltaic sandstones and as a Late Cretaceous formation below the regional Moreno shale, this terminology has been retained for characterization purposes. For correlation purposes, the Moreno shale includes the Ragged Valley Silt formation above the First Panoche sandstone.*

In addition to the inconsistent naming convention, there is uncertainty with the depositional environment at the injection well. Figure 2b, Figure 2c, and Figure 2d show three possible scenarios for the depositional environment expected at Mendota_INJ_1.

- *Figure 2b (likely scenario) shows a scenario in which the Mendota_INJ_1 well is in channel and submarine fan deposits located on the slope of the basin with an updip stratigraphic pinchout into Moreno shales.*
- *Figure 2c (modeled scenario) shows a scenario in which the Panoche Formation*

sandstones of different depositional environments (Figure 2b and Figure 2d) are connected. Because of the correlation in well logs across the model domain, a conservative approach was taken to connect these sandstones for reservoir characterization and reservoir simulation purposes.

- *Figure 2d (less likely scenario), although less likely, is within the mapping uncertainty, in this scenario, the Mentoda_INJ_1 well intersects the distal deltaic shelf deposits.*

If Mendota_INJ_1 is in the submarine fan sandstones (Figure 2b), then there is a much greater chance of an updip stratigraphic pinchout into Moreno shales, providing an additional lateral seal for injected CO2 to the northeast. These sandstones may still have some connection updip through sand-filled channels to the deltaics. Because of these depositional uncertainties and to take a conservative approach to AoR estimation, the geomodel used in site characterization and dynamic modeling considered connected sandstones (Figure 2c). The compartmentalization of the reservoir sandstones can be stratigraphic but also structural. Near the proposed Mendota site, there are two known faults (USGS, 2019) *located approximately 5 miles away, but there are no other major geological features defined. Faults are best interpreted from seismic data. The limited 2D seismic data across the study area show minor structural deformation but any incoherency in the data was interpreted as a possible fault. This interpretation has a high degree of uncertainty because of the vintage of the data but the lack of clear fault offset suggests that large throw faults are not common.*

Figure 3 is a site-specific stratigraphic column at Mendota_INJ_1 that describes the lithology of the Late Cretaceous Moreno Formation, which is underlain by the Panoche Formation. The Panoche Formation is separated into specific sandstone intervals separated by shale layers and labelled First, Second, Third, and Fourth Panoche from youngest to oldest. Injection and confinement zones for the Mendota_INJ_1 well include the Cretaceous First and Second Panoche sandstones and their overlying shale formations separating the sandstones at 8000 to 12000 ft below ground surface (bgs), with the overlying Moreno shale at 7000 to 8000 ft bgs providing regional

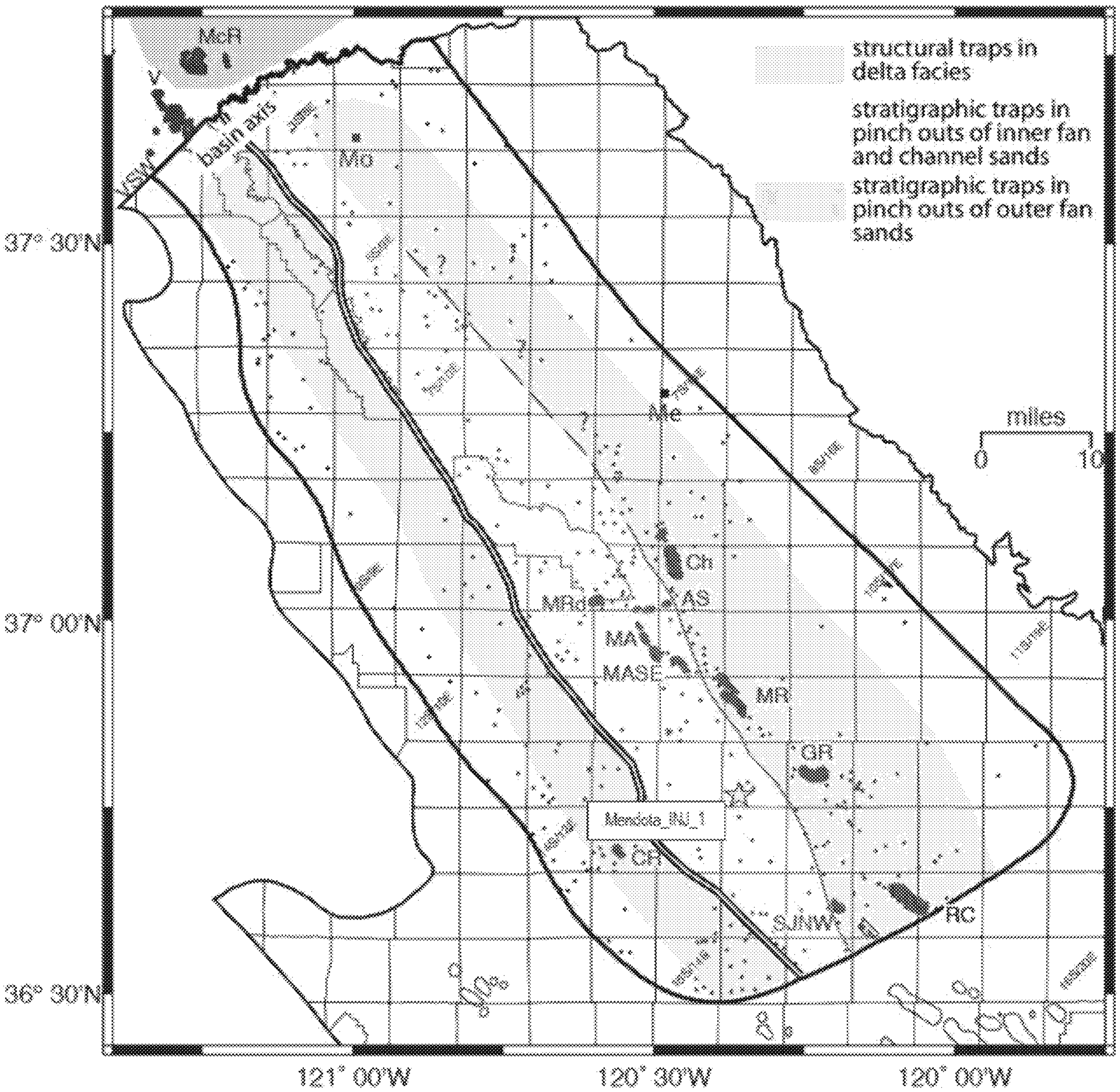

Figure 1: San Joaquin basin depositional model showing structural and stratigraphic traps; The yellow star indicated the proposed Mendota_INJ_1 location.(Hosford Scheirer & Magoon, 2007)

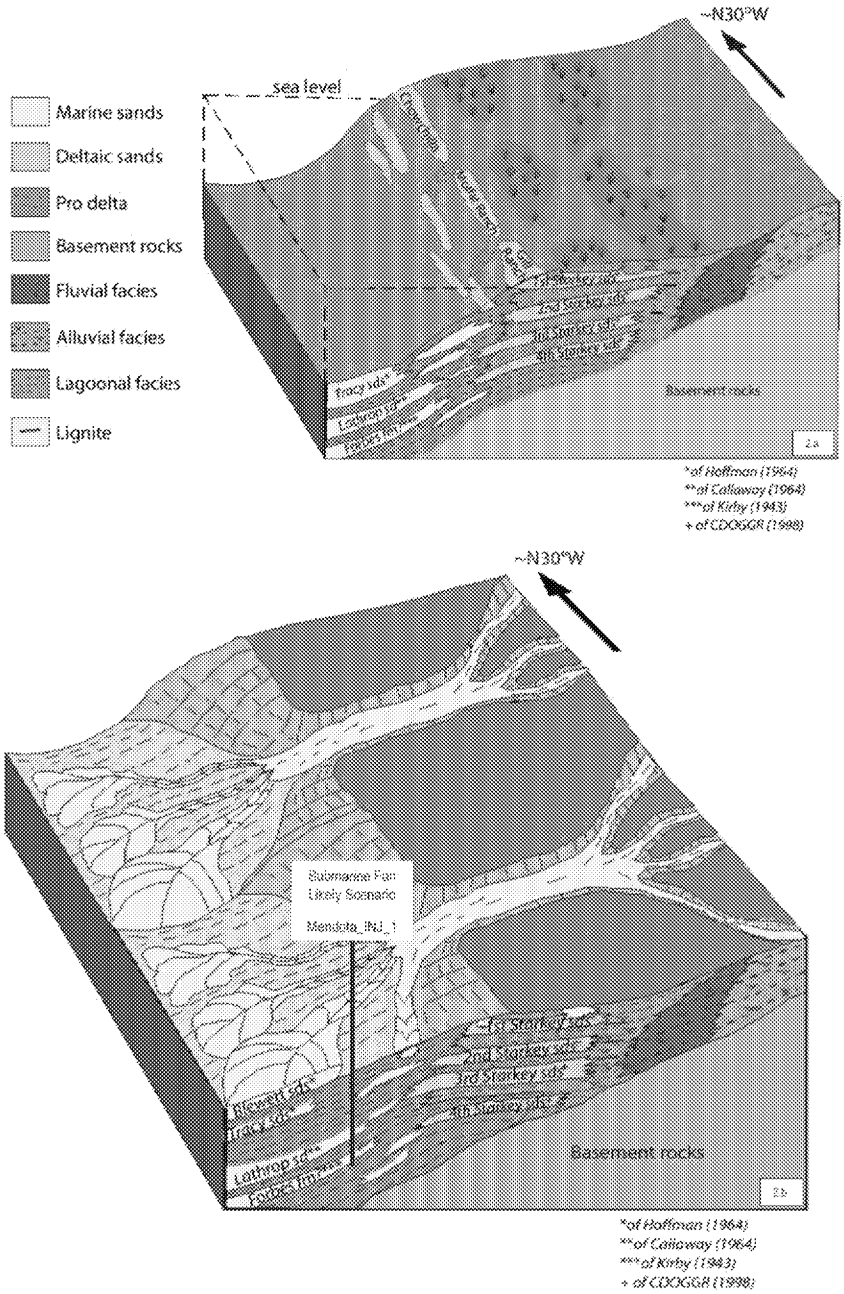

Figure 2a and 2b: San Joaquin basin depositional model showing three possible depositionalscenarios for the location of Mendota_INJ_1. Modified from (Hosford Scheirer & Magoon, 2007)

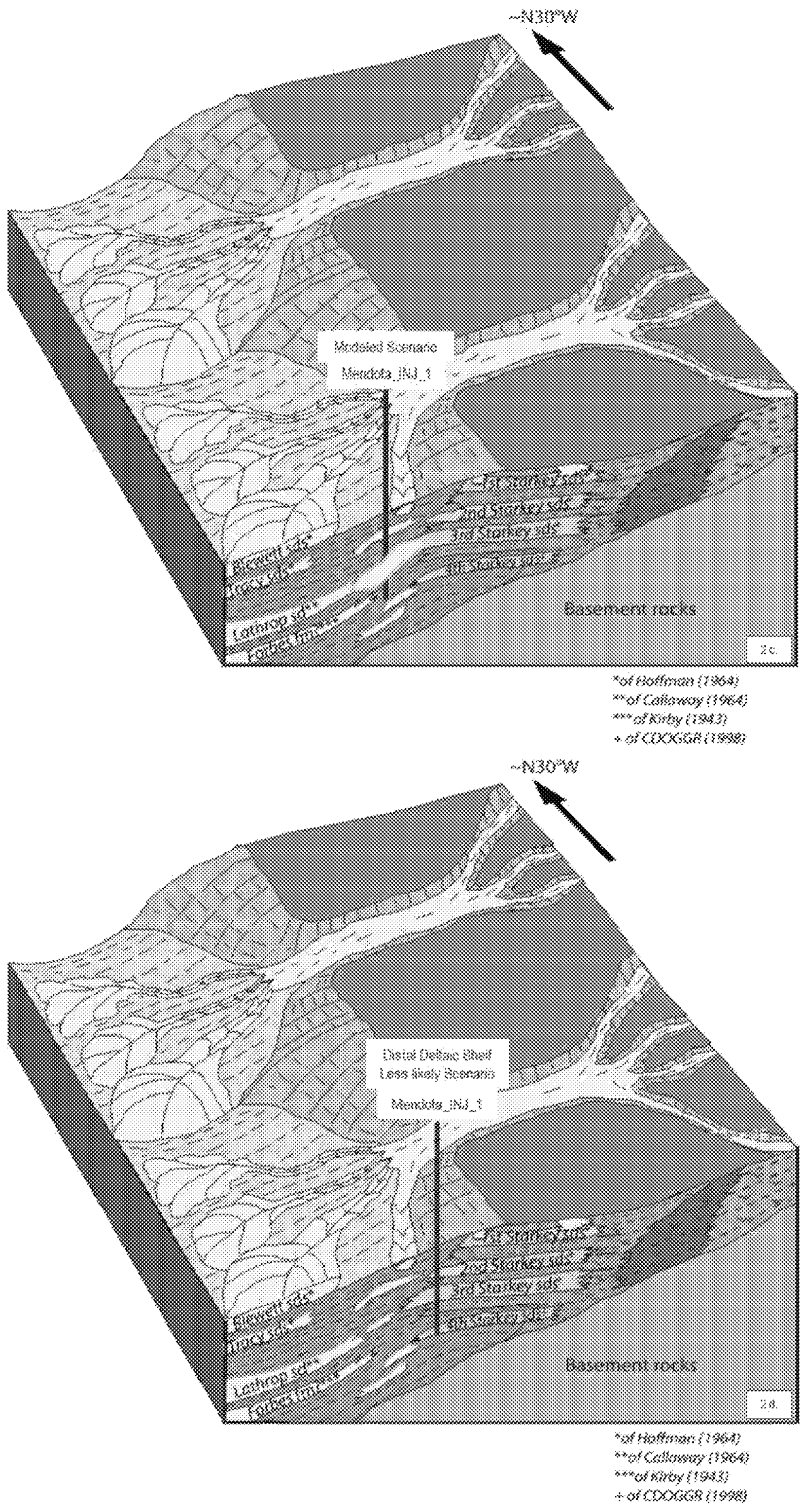

Figure 2c and 2d: San Joaquin basin depositional model showing three possible depositionalscenarios for the location of Mendota_INJ_1. Modified from (Hosford Scheirer & Magoon, 2007)

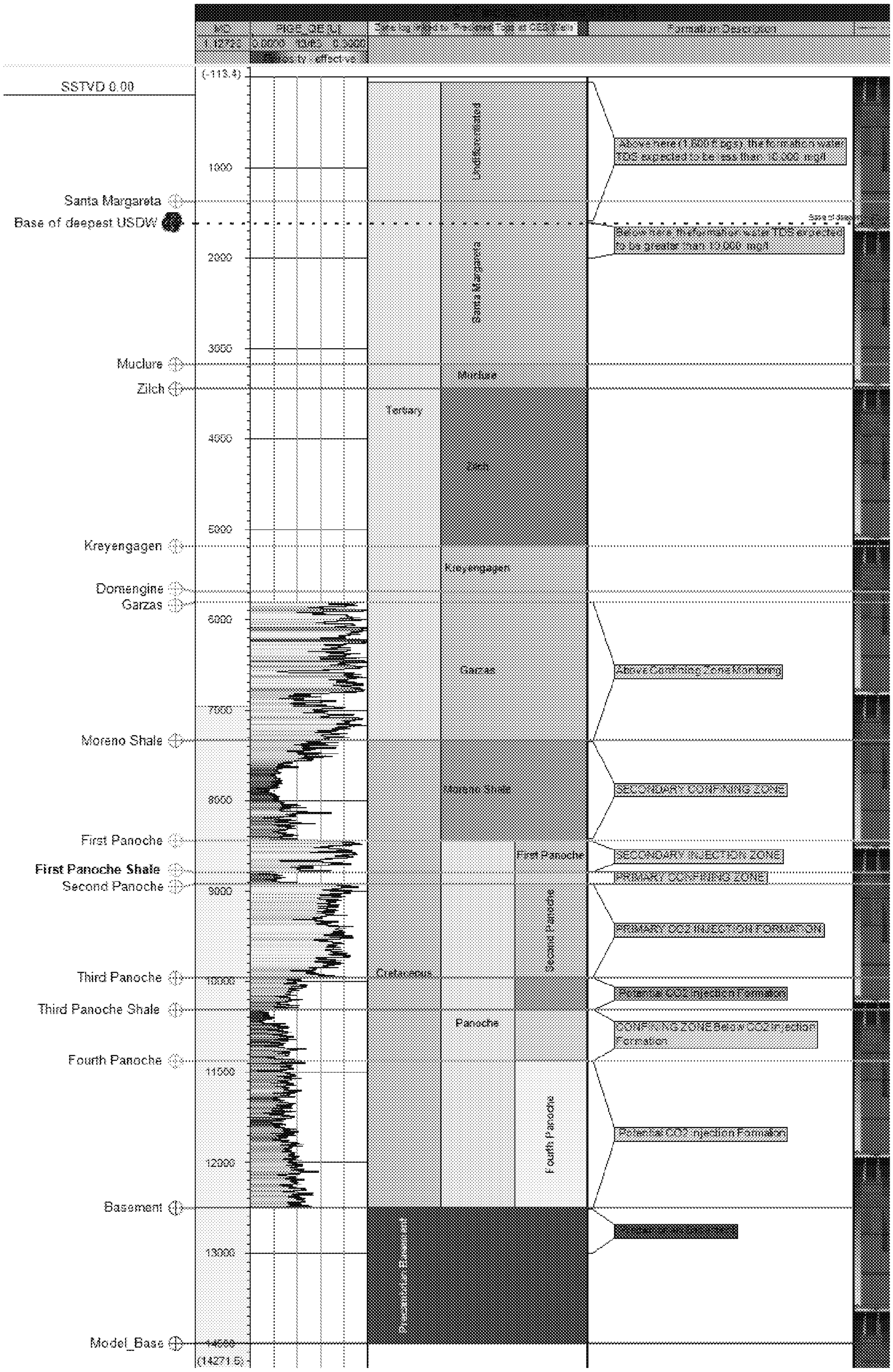

Figure 3: Stratigraphy column. Schlumberger Petrel 2020.*

EPA Evaluation of Response: The overall discussion of the geology and the diagrams is clear and helpful in understanding the regional and site geology. We have a few questions related to the diagrams.

Follow-up Questions/Requests for CES:

- Regarding the locations of the Mendota INJ_1 well in Figures 2a - 2d, are they supposed to be the same? They appear to be in slightly different locations within the block diagram. Is this intended to simply represent uncertainty in where the sands pinch out?
- The Mendota_INJ_1 well location in Figures 2a–2d is supposed to be the same location. The series of diagrams intends to demonstrate the possible depositional environments that Mendota_INJ_1 could encounter. It is also intended to show that a conservative model (one in which all sands are modeled as one flow unit, posing the greatest leakage risk, Figure 2c was pursued for preliminary site characterization due to lack of site-specific data.
- Is the 2nd Starkey the same as the 2nd Panoche? If so, then is it coeval with the Tracy sands? The diagram in Figure 2c (modeled scenario) shows the well penetrating the level of the 3rd Starkey. In the "likely scenario" in Figure 2b, it appears that the well goes as far down as the level of what might be the 4th Panoche sand. Although the 3rd and 4th Panoche sands are potential injection scenarios, should the diagrams in Figures 2a-2d represent the planned injection into the second Panoche?
- Figures 2a–2d are conceptual models of stratigraphy and are not representative of well construction design.

  The following text will be added to the Regional Geology section of the revised narrative attachment to add clarification regarding stratigraphy of the proposed storage complex. This summary should clarify the stratigraphic description and adequately answer questions posed.

Stratigraphy of North San Joaquin Basin

The depositional model for the northern San Joaquin Basin provided in the narrative and subsequent replies describes the depositional setting and expected reservoir or injection zone sandstones for the Mendota_INJ_1 site. This section alludes to the uncertainty in the naming convention and stratigraphy for the proposed injection zone as either part of the deltaic shelf deposits, the slope and basin floor fan deposits, or both, and whether the two are connected. However, the names of the specific target stratigraphic intervals remain problematic because of the inconsistencies in published papers and reports across the basin. A comprehensive report addressing these inconsistencies is USGS Professional Paper 1713), specifically Chapter 5 (Hosford Scheirer & Magoon, 2007). We summarize the conclusions of this report with respect to the Mendota study area and the naming convention applied to clarify the terminology and to support our choice of stratigraphic nomenclature for the Mendota_INJ_1 site.

Hosford Scheirer and Magoon (2007) attempted to apply consistent stratigraphic age, biostratigraphy, and lithostratigraphic boundaries to the geologic column and geological naming conventions in the San Joaquin Basin. As they note, some of the inconsistencies arise from applying similar subsurface correlations and lithofacies names to subsurface stratigraphic units that may not be correlative.

For the late Cretaceous to early Paleocene of the northern Joaquin Basin, they have separated the late Cretaceous to early Paleocene stratigraphic section into a lower Panoche Formation and upper Moreno Formation with the Panoche bracketed between 83.5 to 73.5 Ma and the Moreno from 73.5 to 61 Ma. A lower unconformity separates the base of the section from the Sierran arc basement at 120 Ma from an upper unconformity at the top the section in the middle Eocene. The entire section can be divided into a more proximal stratigraphic section representing the deltaic deposition of the Starkey sands and the more distal slope and basin floor fan deposits (Figure 1).

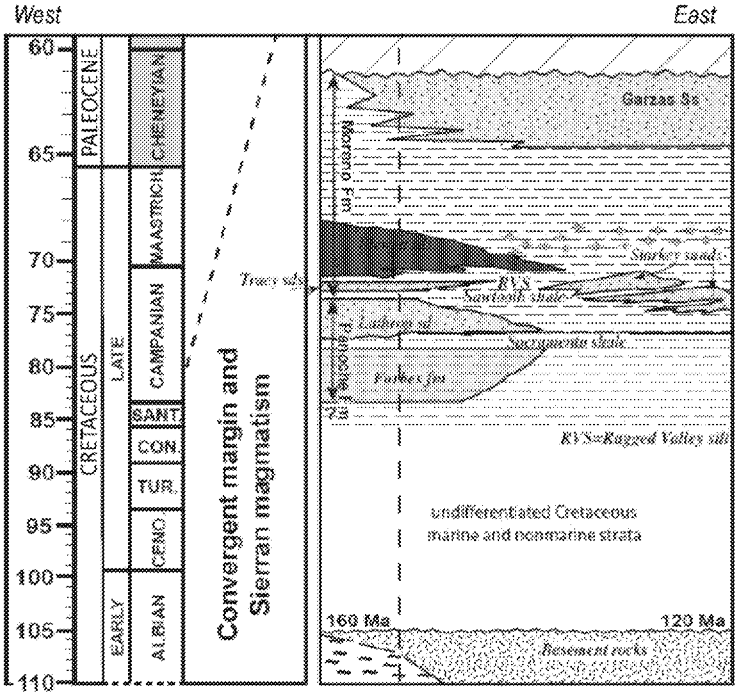

Figure 1. Stratigraphic column from northern San Joaquin Basin showing Cretaceous to Lower Paleocene section. (Modified from Hosford Scheirer & Magoon, 2006).

The Panoche Formation includes in the more distal section to the west a lower Forbes sandstone overlain by the Sacramento shale followed by the Lathrop sandstones. There are no proximal sands in the east that are time equivalent or correlative to the deeper water, more distal Panoche in the west. In subsurface wells, the Panoche sands have been labeled as first, second, third, and fourth Panoche sands. These picks may or may not correspond to the specific sands labeled but may be sands within these members.

The Sawtooth shale overlies the Lathrop sands and is the lowest member of the Moreno Formation. This shale is overlain by the Tracy sands followed by the time-transgressive Ragged Valley silt and the Blewett sands, which underlie the Moreno shale, which is a regional top seal. The Cretaceous to Paleocene widespread Garza sandstone is the youngest unit in the Moreno Formation.

Unlike the Panoche Formation, the members of the Moreno Formation to the west are coeval to sands in a more proximal location to the east, which are the Starkey sands. These are interpreted as three principal sand units often identified as Starkey one, two, and three, and they correlate distally with the Sawtooth shale, Tracy sands, and Ragged Valley silt. In some instances, the lower Starkey sands are considered coeval with the Panoche Lathrop sands.

Although the USGS provides a current interpretation of the stratigraphic correlations for the Cretaceous section in the northern San Joaquin basin (Hosford Scheirer & Magoon, 2007), there remains debate about which formations specific sandstones should be assigned to, or, in the subsurface, even which sandstones are intersected by the wells. For instance, the USGS report Chapter 21 has reproduced historical maps and well sections, such as that from the Gill Ranch Field, where the Starkey sands have been labeled as Panoche first to fourth Panoche. In fact, the historical log and cross-sectional images in Chapter 21 of the USGS report highlight the inconsistencies in the labeling of the stratigraphic sections.

For this reason, and to avoid confusion and incorrectly labeling a sandstone target for the target well in the Mendota site, we have chosen to label all sandstones as Panoche in a respective Panoche Formation, which may include sands from the Moreno Formation as described in *Hosford Scheirer & Magoon, 2006*. We label the first sandstone top beneath the Moreno shale as First Panoche sand and incrementally increase the number for each subsequent sandstone. Based on the stratigraphic setting, description, and local well constraints, we are confident we will intersect sands. We cannot with accuracy determine, however, whether we will intersect the more distal or proximal sands or something in between. For instance, it might be possible that the well intersects as the First Panoche sand, the top of the Moreno Blewett sandstone, but subsequent sands are the distal terminations of the Starkey sands. If the section intersected is the more distal sands, there is a greater chance that these will terminate updip into shales. However, if the Starkey sands are intersected by the well, there may be communication updip. We view this as an unlikely scenario given the proposed well distance from the paleo shelf edge. However, to consider this riskier scenario for updip CO_2 migration, we have modeled sands connected from the proximal to the distal locations.

2 Regional Geology and Geologic Structure

The Mendota site is located within the central San Joaquin Basin, situated along the basin's deepest axis. The basin contains 25,000 feet of sediment, spanning various changes in sea levels and tectonic settings. The San Joaquin Basin trends NW-SE and is aligned with the Sierra Nevada at its eastern edge. The proposed injection zone, the Cretaceous age First and Second Panoche Sands of the Panoche Formation, and confining layer, the Moreno Shale, pinch out against the Sierra Nevada basement rocks to the east. In addition to the Moreno Shale, laterally heterogenous turbidite deposits form interbedded shales that act as stratigraphic traps within the Panoche Formation (page 15). The central San Joaquin Basin is shown in a depositional model in Figure 3 and cross section in Figure 4 (page 16) and stratigraphic column in Figure 5 (page 17). In this part of the basin, the subsurface dip is approximately 4 degrees to the SW (page 18).
CES delineated a pressure-based area of review (AoR) that extends over a 2.2 square miles surface area to the northeast of the proposed injection well (it is all within a 2-mile radius to the northeast).

The permit application is based on log data from 10 wells to the north, east, and south of the proposed injection well. Resistivity logs were run in all 10 wells; most also have spontaneous potential (SP) or compressional slowness (from acoustical logs) or both; 3 have gamma ray, bulk density, and neutron porosity logs. Core samples are available from 1 well (NAPA AVE A/1, about 3 mi to the east). While there are no well data to the west of the proposed injection well, CES acquired 2D seismic data for areas to the west.

3 Faults and Fractures

To evaluate the faults and fractures in the region and in the AoR, CES gathered faulting data from public sources and interpreted them locally across three 2D seismic lines (Figures 16-18). These seismic lines are shown in three dimensions in Figure 19 (page 31). Most of the faults in the area are small throw features, with a few exceptions. Faults 1 and 2 trend north and separate the Mendota AoR from the Gill Ranch Field to the east. These are shown in the seismic line in Figure 16. The location of Fault 1 is indistinct, and more information is needed for accurate positioning (page 26). Faults 3 and 4 are located nearer to the proposed injection well and have small normal displacement, but do not appear to extend above the Third Panoche Formation. Fault 13 dips approximately 30 degrees SE and passes below the Mendota_INJ_1 well injection target at a depth of 9,850 TVDSS. The exact nature of this feature is unknown, but because its dip orientation is perpendicular to the regional principal stress direction of ~N45E, CES interprets the fault as strike-slip or due to wrenching or differential settlement in the basin (page 26).

A fault seal analysis was conducted on Fault 13 using a geocellular model. Based on this analysis, CES concluded that sediment displacement across the fault is likely low, and that injected fluid will therefore be confined to the Second Panoche Sands injection zone. If sediment displacement is high, injected fluids may migrate but would be limited to zones below the Moreno Shale because the clay from the Moreno would smear along the fault during displacement (pages 26-27). The clay content, based on Fault Clay Prediction, is shown in Figure 22 (page 33). At this time, no hydrocarbons have been identified in exploration wells to determine whether the fault is sealing. Furthermore, CO2 plume simulations show the plume migrating to the northeast, away from Fault 13 (page 27).

3.1 Questions/Requests for CES:

- *What are the blue lines that trend NW-SE in Figure 14? Do these represent faults, and if so, which ones?*
  - *The blue polygons trending NW-SE in Figure 14 do represent surface faulting identified by the USGS (https://mrdata.usgs.gov/geology/state/map-us.html). The subsurface locations and names of these faults are currently unknown. Field pool data from Gill Ranch estimates the western fault dips east and the eastern most fault is near vertical.*
- *The text on Figures 16-19 is difficult to read. In particular, it is not possible to identify Faults 1, 2, 3, 4, and 13 on Figure 19. Are higher resolution figures available?*
  - *The images in Figures 16-19 were captured at a higher resolution, with additional labeling of key faults and reformatted from portrait to landscape. Please refer to Appendix A: Updated Figures.*
- *On page 15, the application states that there are two known faults near the Mendota site. To which two faults does this refer?*
  - *The two faults referenced on page 15 are the same two faults within the Gill Ranch field discussed in the first question above. The USGS does not explicitly name these faults.*
- *What is the extent of the planned 3D seismic survey?*
  - *The extent of the planned 3D seismic survey is designed to contain full fold and maximized azimuth distribution over the modeled area of the plume after 20 years of injection. The fold and azimuthal distribution will taper away from the plume edge.*

EPA Evaluation of Responses: The responses in this section are adequate given available data, and the updated figures are helpful.

3.2 Objectives for Pre-Operational Testing:

- *Determine the position of Fault 1 via 3D seismic data.*
  - *3D seismic will be acquired to better define the geometry of all faults within the plume area.*
- *Determine the nature of the displacement of Fault 13.*
  - *By combining the 3D seismic data interpretation with a geomechanical model calibrated to core and well test data, the dynamic mechanical stability and displacement along the fault can be determined either through analytical or numerical stress analysis. Since there is uncertainty associated with the current*

location of the faults interpreted on the 2D seismic lines - (especially Fault 13, which is interpreted on the E-W seismic lines, but not evident on the seismic line closest to the well), the 3D seismic interpretation will improve the position and relative displacement of the faults.

- *Collect core data to demonstrate the sealing capacity of Fault 13.*
  - *Core data will be collected from the monitor and injection well locations.*
  - The location of Fault 13 is uncertain and possibly may not even exist (because of the nature of *interpreting on 2D seismic and the distance between the 2D seismic lines). Also, the injection well as currently planned, stops several hundred feet above the interpreted fault therefore the well does not intersect the interpretation for Fault 13. Since the injection well stops above the interpreted Fault 13 no core data can be collected across Fault 13s location. The core analysis results will validate the geomechanical model which will facilitate a more reliable assessment of the fault stability.*

- *Perform 3D geomechanical modeling based on data collected via well logs, geomechanical core analysis, and well testing, combined with 3D seismic data to better characterize the faults in the area and determine their sealing capacity and that they are non-transmissive.*
  - *3D seismic will be acquired to enhance the fault geometry throughout the area. The same methodology referred to above in determining the displacement of Fault 13 will be applied to the faults in the survey area. The improved interpretation of the fault and horizon data and the integration of the well data will better constrain the analysis of any cross-fault transmissivity and associated risks.*

EPA Evaluation of Response: CES's notes above are acceptable. The proposed sample collections and seismic modeling should provide a good basis for our understanding of the fault and fracture activity at the Mendota site.

4 Depth, Areal Extent, and Thickness of the Injection and Confining Zones

The First Panoche Sandstone is regionally located at 8,000-12,000 feet below ground surface (bgs). Based on the stratigraphic column (Figure 5), the Second Panoche Sands (the primary injection zone) is approximately 8,900-10,000 ft bgs. A second, potential injection zone is the Fourth Panoche, located from about 10,900-12,500 ft bgs. These intervals are also shown on the cross section in Figure 6. Section 2.2 of the application narrative states that the proposed injection targets are the First and Second Panoche Sands, whose tops are estimated at depths of 8,437 and 8,918 ft bgs, respectively. Formation surface maps (Figure 12) and isochore maps (Figure 13) show that all units are laterally continuous across the region.

According to the isochore maps in Figure 13, the First Panoche ranges in thickness from about 275 to 750 ft across the 5-mile radius from the Mendota site, the Second Panoche ranges from 780 to 1,170 ft, and the Fourth Panoche ranges from 1,400 to 2,500 ft.

The primary confining layer is the Moreno Shale, which is regionally located directly above the Panoche

Formation at 7,000-8,000 ft bgs. On the stratigraphic column in Figure 5, the Moreno Shale is located at 7,350-8,450 ft bgs (page 17). According to the isochore map in Figure 13, the Moreno Shale ranges in thickness from about 500 to 1,650 ft across the 5-mile radius from the Mendota site.

Secondary stratigraphic seals are provided by shales within the Panoche Formation. According to Figure 5, the First Panoche Shale is from 8,800-9,000 ft bgs, and the Third Panoche Shale is from 10,300 to -10,900 ft bgs. According to the isochore maps in Figure 13 (page 25), the First Panoche Shale ranges in thickness from about 60 to 190 ft across the 5-mile radius from the Mendota site, and the Third Panoche Shale ranges from about 200 to 1,100 ft.

The north-south trending cross sections are corroborated by the 2D seismic data, in terms of dip and approximate formation depths. The images based on seismic data do not show the separate shale layers within the Panoche Formation, whereas the cross-section does. This will be confirmed via pre-operational testing and the planned 3D seismic survey.

The table below summarizes the depth and thickness of the formations of interest.

Unit	**Depth**	**Approximate thickness across AoR (Figure 13 isochore maps)**
Moreno Shale	7,332 ft bgs (Narrative pg 18)	500-1,650 ft
First Panoche	8,437 ft bgs (Narrative pg 18)	275-750 ft
First Panoche Shale	8,800 ft bgs (Figure 5)	60-190 ft
Second Panoche	8,918 ft bgs (Narrative pg 18)	780-1,170 ft
Third Panoche	9,950 ft bgs (Figure 5)	150-750 ft
Third Panoche Shale	10,300 ft bgs (Figure 5)	200-1,100 ft
Fourth Panoche	10,900 ft bgs (Figure 5)	1,400-2,500 ft

4.1 Objectives for Pre-Operational Testing:

- *Confirm thicknesses and depths of the injection and confining zones at the Mendota site through seismic imaging and information gained during drilling of the proposed injection well and deep monitoring well.*
    - *The thicknesses and depths of the injection and confining zones at the Mendota site will be confirmed with the use of 3D seismic and data gathered while drilling the injection and monitoring well.*

EPA Evaluation of Response: CES's confirmatory note here is acceptable.

5 Hydrologic and Hydrogeologic Information

The lowermost underground source of drinking water (USDW) is an unnamed interval within the Santa Margarita Formation that is estimated to be present around 1,600 ft bgs (page 18), or 1,415 ft TVDSS (page 57); this is located 7,165 feet above the top of the Second Panoche Sands (page 59). The total dissolved solids (TDS) content was determined by applying Archie's equation to the resistivity logs of 5 wells to the north and south of the Mendota site to determine TDS values. CES states that calculated salinity indicates that the base of the USDW is between 1,200 to 1,450 feet TVDSS. Uncertainties in this estimate include formation porosity, Archie equation parameters (standard parameters were used for now), and the effects of clay (page 57).

According to field data sheets for wells located in nearby oil and gas fields, the Jergins Formation at Cheney Ranch and the Blewett Formation at Merril Ave have salinities of 8,500 and 15,000 mg/L, respectively. The Jergins and Blewett Formations are in the Moreno Shale. Salinities of these sands at the Mendota site will need to be confirmed via sampling and analysis during drilling of the characterization well.

CES retrieved shallow groundwater well information from the California Department of Water Resources. There are 525 active and non-active water wells within a 5 mile radius of Mendota_INJ_1, in all directions from the proposed site. Accurate locations of these wells are not known at this time. The wells range in depth from 50 to 500 feet. Their water levels, which were recorded at the time of drilling, were used to estimate groundwater elevation and flow direction. At the Mendota site, the shallowest groundwater is around 32 feet bgs (114 ft TVDSS). The San Joaquin River flows north south and is 0.6 miles east of the site. For the AoR and Corrective Action Plan in Attachment B, CES used a fixed well search radius of 2.5 miles in order to account for uncertainty in the model, and so the water well summary in that document does not agree with the application narrative (Section 5.1.1 of Attachment B).

5.1 Questions/Requests for CES:

- *The application states that the base of the lowermost USDW is estimated between 1,200 to 1,450 feet TVDSS, while the depth to the USDW is estimated at 1,415 TVDSS. Please clarify the discrepancy.*
    - *The lowermost USDW is estimated between 1,200 to 1,415 feet TVDSS. The estimation is based upon log calculations thus there is some uncertainty which will be resolved when data becomes available from the drilling of a well.*
- *Please provide a legend or labeled contours for the potentiometric map in Figure 47.*
    - *Figure 47: Potentiometric map of the approximate shallowest groundwater surface was updated with labeled contours. Please refer to Appendix A.*
- *What is the vertical distance between the First Panoche Sands and the lowermost USDW?*
    - *At the proposed injection well location, Mendota_INJ_1, the vertical distance from the First Panoche Sandstone to the calculated lowermost USDW(1,415 TVDSS) (10,000 TDS) is 7,018 ft. This clarification was added to Figure 46. Please refer to Appendix A: Updated Figures.*
- *Figure 46 includes a line marking the base of fresh water at 10,000 TDS. Section 2.7.1 of the application narrative discusses a BFW of3,000 mg/L. Please confirm that no evaluations of the lowermost USDW are based on a definition of3,000 mg/L.*
    - *The lowermost USDW in this application always refers to the 10,000 TDS limit. The California regulations of3,000 mg/l (base of fresh water) was used as a quality control check when reviewing well reports.*

- *Figure 45 also appears to demarcate the BFW and the USDW based on salinity, but the resolution of the figure is too low to read the legend. Please provide a higher resolution version of Figure 45.*
    - *Figure 45 has been incorporated with higher resolution. Please refer to Appendix A: Updated Figures.*

EPA Evaluation of Response: The answers are helpful and shed light on some of the questions, however we have a few follow up questions.

Follow-up Questions/Requests for CES:

- If the method of estimation to the top of the USDW was the same as the method of estimation for depth to the base of the USDW, how would it be possible for the base to be any higher than the estimated top at 1,415 ft TVDSS?
    - The estimate for the top of the USDW is neither considered nor provided; any formation fluids above the base of USDW to the surface elevation are considered USDW. The data provided in the application and subsequent replies are a range representing the base of the USDW. Salinity back-calculated from Rw (resistivity of water) show an estimated base of freshwater at approximately 1,415 ft.
- The resolution of the updated Figure 45 is still too low. Even with the addition of lines marking a point of 10,000 ppm TDS, it is unclear on what basis the BFW and USDW are delineated, since these points do not always coincide. Please explain the basis for separating the BFW and USDW in Figure 45.
    - Figure 45 will be updated with a higher resolution. The leftmost track was generated using zonal tops where BFW (3,000 ppm) information was captured from well records and used as a top input for preliminary mapping (CalGEMS, 2020). The CalGEMs historical well records do not provide information on how the BFW (3,000 ppm) was determined. In the analysis conducted for Mendota_INJ_1, the USDW (10,000 ppm) was determined by back-calculating salinity (ppm) from resistivity of water, with the resistivity of water being calculated using resistivity and porosity.

5.2 Objectives for Pre-Operational Testing:

- *Sample formation water collected during drilling of the injection and monitoring wells to determine the base of the lowermost USDW and confirm that available resistivity logs and data from nearby fields is representative of the Mendota site.*
    - *Formation water samples will be collected (when water is present) during the drilling of the injection and monitor wells. The newly acquired resistivity log data will be compared to the other well data available in the area.*
- *Verify the salinities for the permeable Jergins and Blewett formations within the Moreno Shale at the Mendota site to confirm that none are USDWs.*
    - *Water samples will be collected within the Jergins and Blewitt formations (when water is present) and analyzed to confirm whether the formations are USDWs.*

EPA Evaluation of Responses: CES's responses are acceptable.

6 Geochemistry

6.1 Characteristics of Injection Zone Formation Water

There was no available formation water information in the Panoche Formation at the Mendota site. Available formation water information from nearby oil and gas fields shows that TDS is 20,900 mg/L in the Panoche Formation at Gill Ranch, and 14,000 mg/L in the Moreno Shale at Cheney Ranch (Table 6).

There appears to be only one data point in the table for the Panoche Formation, at Gill Ranch, which is approximately 6.5 miles to the northeast of Mendota. The table does not indicate which Panoche Sand the value represents, and the depth is shallower than the target formation at the Mendota site. The text states, however, that there are wells at Gill Ranch that penetrate through the Fourth Panoche Sand. CES anticipates a salinity of about 25,000 mg/L at the Mendota site, although it is not stated what this is based on other than possibly a general increase in salinity moving westward.

CES states that logs from wells in the AoR do not indicate that any sand unit has formation water fresher than the Panoche Formation and acknowledges that this is an area of uncertainty. CES also states that formation water sampling for the Panoche Formation and overlying sands is included in the proposed testing plan in Attachment G. The plan indicates fluid testing for geochemistry in both the proposed injection well and observation well. Table 10 of the Testing and Monitoring Plan identifies analytical and field parameters for fluid sampling in the injection zone. It includes TDS along with a suite of other parameters.

6.1.1 Questions/Requests for CES:

- *Were any of the data values in Table 6 based on fluid sampling or well logs? If so, how many data points do the values represent?*
    - *The aqueous chemistry data in the report* (Conservation, 1998) *are actual fluid samples. CES assumes these were collected under standard operating procedures in line with state reporting requirements. The report does not provide the sampling methods, but they are typically obtained and separated at the wellhead. The report does not specify the number of samples or from which wells the samples were taken for each formation, nor the actual depths of the samples. It is assumed the values represent averages from a specific formation from several wells.*

- *The data point from Gill Ranch is 6.5 miles away and represents a depth shallower than the Mendota injection zone. Cheney Ranch is approximately 12 miles southwest of the Mendota site. Please provide information to demonstrate the degree to which data from these fields are representative of the Mendota site.*
    - *Formation water from the Gill Ranch field is likely similar to that of the Mendota site as they may share the same initial pore water (sea water) during deposition and similar porewater evolution; however, the lateral continuity of the sandstones between these sites is uncertain and they may have discontinuous hydrologic systems. The sandstones at Gill Ranch are located up dip and could be deltaic whereas those near the injection location are expected to be turbidites on slope. There is a greater possibility of meteoric water infiltration into the sandstones up dip and dilute the*

pore water during the burial history, which indicates higher salinity in the injection zone. Since the Cheney Ranch field targets sandstone above the Panoche formation in the Moreno formation (Jergins sandstone), it is uncertain whether the data points from this field are representative of the Panoche formation at the proposed Mendota_INJ_1 site. Fluid samples from the injection zone are required to confirm the formulation fluid chemistry.

EPA Evaluation of Response: Because CES will be collecting pre-operational data, we understand that the site- specific geochemical characteristics will be characterized at a later time. Our questions below about the existing data aim to better understand the existing data and how it will eventually be compared to site-specific data (and should be addressed in the updated permit application that will be submitted prior to construction). However, this data (and the clarity) are not as crucial to understanding the proposed site as the planned pre-operational data collection. The first answer in this section is acceptable.

Follow-up Questions/Requests for CES:

- CES states that the data source (Conservation, 1998) does not provide the depths from which samples were taken, sampling method, number of samples, or the specific wells where the samples were collected. Are there available additional sources that can be used to corroborate the findings from the Conservation report?

- The Conservation report only provides average depths of the sand units from which the water data were obtained. The depths in Chapter 6.1 and Table 6 are average depths of the sand units. The water samples obtained from the wellheads are mostly from the perforation depths, which are not provided in the report.
- Additionally, three injection wells (API: 3900052, 3900053, and 3900057) and two production wells at Gill Ranch Gas Field have recorded depth to base of freshwater in USGS data (Davis et al., 2018) from 650 to 965 ft. This is much shallower than the Panoche sands as labelled in the Gill Ranch Field which are expected to have higher salinity at their depths greater than 5000 ft.
- Citation
  Davis, T.A., Bennett, G.L., Metzger, L.F., Kjos, A.R., Peterson, M.F., Johnson, J., Johnson, T.D., Brilmyer, C.A., and Dillon, D.B., 2018, Data analyzed for the preliminary prioritization of California oil and gas fields for regional groundwater monitoring: U.S. Geological Survey data release, https://doi.org/10.5066/F7FJ2DV3.
- Table 6 includes depths for the samples taken. Can CES confirm the source of these depth values, if they are not from the Conservation report?

- The depths in Table 6 are average depths of the geologic units from which water samples were obtained. They are from a DOGGR report (DOGGR, 1992). The average depth may be somewhat different from the perforation depths of the wells at which the formation waters were sampled. The report does not provide the well IDs or the perforation depths (water sample depth).
- On page 63 of the Permit Application Narrative, it is stated that, "The salinity tends to increase to the west away from the recharge area (Gillespie, 2017) (pg. 63)," but the lowest salinity value recorded in table 6 comes from Cheney Ranch, 12 miles west of the proposed site. Is there additional evidence to support the assertion that salinity increases towards the west, or can CES provide reasoning for the low salinity value reported at Cheney Ranch?

- The data point from the Cheney Ranch Field is from the Jergins sand in the Moreno shale, a different stratigraphic unit from the stratigraphic intervals near the proposed injection well site. This sand is not laterally extensive as it is not present in nearby fields, and its hydrologic system is likely not connected to the proposed Panoche sands. Therefore, this data point may not be a good indicator for the salinity in the sands of the Panoche formation as defined in this report.

6.1.2 Objectives for Pre-Operational Testing:

- *Confirm the TDS values in the sand units within the Panoche Formation and in the Moreno Shale.*
  - *If recoverable formation water is present, samples will be collected and analyzed. As part of the water analysis the TDS will be calculated.*

- *Obtain a complete water analysis in the injection zone to provide inputs to support the geochemical modeling and determine whether available data from nearby fields is representative of the Mendota site. The analytical parameters should match/provide a baseline for future testing and monitoring.*
  - *The planned water analysis will include the below analytical parameters; these results will provide a baseline to be used for future testing and monitoring which will confirm whether the available data from nearby fields are representative.*
    - *pH*
    - *Specific gravity o Resistivity/Conductivity*
    - *TDS (Total Dissolved Solids)*
    - *Turbidity*
    - *Total Hardness*
    - *Inductive Coupled Plasma (ICP) for cations*
    - *High Pressure Ion Chromatography for anions*
    - *Dissolved gases (H_2S, CO_2, O_2, etc)*

EPA Evaluation of Response: The proposed pre-operational tests are adequate to support the geochemical modeling effort. All of these parameters are identified in the Testing and Monitoring Plan, except specific gravity, turbidity, hardness.

Follow-up Questions/Requests for CES:

- Please also include specific gravity, turbidity, and hardness in the Testing and Monitoring Plan for consistency.

- Table 7 in the Testing and Monitoring Plan includes the above-mentioned tests for specific gravity, turbidity, and hardness as well as the full range of tests that will be performed.

6.2 Mineral Composition of The Injection Zone

Mineralogic information for the injection zone comes from the Fourth Panoche Sand at the B.B. Co 1 well, which is in the AoR (within 2.5 miles northeast of the proposed injection well). The estimated mineral composition for the Panoche Formation described in Table 7 is proposed for geochemical modeling. However, Table 7 does not specify which Panoche sand layers the data represents. Data specific to the targeted injection zone (i.e., the First and Second Panoche Sands) at the Mendota site will be needed.

Table 7: Estimated mineral composition (wt. %) for the Panoche Formation used in geochemical modeling

Quartz	K-feldspar	Plagioclase	Calcite	Pyrite	Muscovite	Chlorite	Illite	Kaolinite
60	10	15	4.5	0.5	2	2	6	Trace

The testing plan in Attachment G describes planned core analysis by x-ray diffraction for core samples in both the proposed injection well and deep monitoring well.

6.2.1 Questions/Requests for CES:

- *How many core samples are proposed to be analyzed and from what depths?*
  - *A combination of whole core and mechanical sidewall plugs will be taken from the well to ensure the best coverage for characterizing the formations. Whole core will be taken over sections of the Moreno Shale, First Panoche Sandstone, First Panoche Shale, Second Panoche Sandstone and Third Panoche. Mechanical Sidewall plugs will be taken over specific points not covered by whole core and on any other areas of interest identified from logs and drilling. Current estimates of whole core footage will be in the several hundred feet range and in the tens of plugs taken from the mechanical sidewall tool. Footages of whole core and number of plugs from mechanical sidewall may increase or decrease due to core acquisition and drilling information. An HRA (Heterogenous Rock Analysis) provides a mathematically precise methodology (derived from Triple Combo Logs) for rock typing and will assist in determining the number of samples to be taken that for each rock type identified in the well.*
  - *Cuttings will be used to provide minerology from overlying and underlying formations. Sample spacing would be in the range of 20 to 30ft.*
- *Does CES propose to perform other analyses of core samples besides XRD to document the mineralogy of the injection zone (e.g., polarized light microscopy)?*
  - *As noted, the XRD analysis will provide an averaged minerology per sampled depth interval. o*
  - *Other recommended core analyses that will be used include:*
  - *XRF (using FIT/FIS technique), on cuttings along the entire zones of interest.*
  - *DRIFTS (using FIT/FIS technique), on cuttings along the entire zones of interest.*
  - *XRD on a subset of the XRF samples, as well as on samples from the collected whole core and rotary core samples.*
  - *Thin section analysis at the same locations where XRD was conducted.*
  - *SEM-EDX on a subset of the XRD samples as determined by thin section analysis.*

EPA Evaluation of Response: The proposed core sample analyses should provide a good understanding of the target formations' geochemistry, and the spacing range of 20-30 feet per sample should provide sufficient resolution.

6.2.2 Objectives for Pre-Operational Testing:

- *Obtain a mineralogic analysis of the injection zone and confining zone solids that represents the Mendota site.*
  - *Please refer to above reply on the recommended core analysis.*

7 Geomechanical and Petrophysical Characterization

Petrophysical properties of the injection and confining zones were estimated using the well log data from 10 wells to the north, east, and south (primarily to the east) of the proposed injection well drilled between 1942 and 1987 (Table 2); the data were analyzed using Techlog software. Only two of the wells listed in Table 2 are within the 5-mile radius as shown in Figure 8--these are B.B. Company /1 (2.32 miles to the northeast) and Sterling-Coleman/1 (about 4 miles to the southeast).

The well log data were upscaled and used as the basis for populating properties throughout a geomodel, which ultimately supports numerical modeling of the Mendota site.

On page 34, CES states that "The petrophysical workflow involved building a model using well log data from NAPA AVE A/1 calibrated to core data for the same well (TGS, 2019)." The NAPA AVE A/1 well is 3 miles east of the site.

7.1 Questions/Requests for CES:

- *Given that the available porosity and permeability values are based on logs from 10 wells of different ages and spread over several miles, what information is available to demonstrate that these are comparable and representative of the Panoche Formation within the AoR?*

- *Although the wells are spread over several miles they are located in the same Cretaceous depositional setting of the proposed injection well based on regional mapping and published interpretation* (Hosford Scheirer & Magoon,Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province,California, 2007). *The well nearest to the AoR that reaches the Panoche formation is B.B COMPANY/1 (2 miles NE of Mendota_INJ_1). Digital log responses from B.B COMPANY/1 show sandstones that correlate across the 10 petrophysical wells below and above the First Panoche shale. These sandstones are interpreted as either part of the distal deltaic sandstones or the channel fan sequence on the slope. CES expects that within these sequences there may be some minor differences in mineralogy, grain size and porosity, but that, in general the properties will be similar. The small difference in depth to the reservoir sandstones between the closest well, B.B COMPANY/1, and the proposed injection well regardless of whether the sandstones are in physical communication suggests also that the petrophysical properties are likely comparable to Panoche sandstones modeled in the AoR.*

  EPA Evaluation of Response: The response is adequate given the amount of available information.

- *What method(s) was/were used to calibrate the well log data to the core data?*
  - *The primary method used to calibrate the petrophysical model to the cored data is taking the core variables and overlaying it on top of the corresponding well log or*

processed log variables for comparison and making model adjustments as needed. In addition to performing a direct comparison, the data was also plotted as trend vs depth (increase permeability/porosity, changing clay volume with depth). These comparisons provide insight on how the well variables align with the core data. Adjustments were made to hone the model to improve the relationship between core and well/processed logs. In the model, endpoints of the minerals were altered, constraints on volume of minerals, and other adjustments were made in the porosity / permeability relationship to enhance the correlation.

EPA Evaluation of Response: The response explains the general approach. If we understand correctly, the petrophysical properties were estimated from well-bore data using the Techlog* Wellbore Software Platform and the Quanti.Elan* multicomponent inversion solver and were estimated independently from laboratory analysis of the core data. The response above indicates that the model for permeability and porosity from well lab data was then calibrated via overlay with the depth-matched core data.

We understand that calibration would be refined once site-specific well logging and core data are available.

The narrative states on page 38 that, "The total porosity of the injection zone was determined from either the bulk density or compressional slowness depending on data availability (Figure 27)." We assume that when well logging is complete for the injection well, that petrophysical estimates will be able to be done synthesizing multiple logs (sonic, density, neutron, etc.) for a refined estimate.

Follow-up Questions/Requests for CES:

- *Is our understanding regarding methods used to calibrate the well log data to core data correct?*
  - Your understanding is correct. After logs and core have been obtained from the injection well, permeability and porosity estimates will be refined, and geology and reservoir models will be updated using these data.

- *What is the error/variability associated with these methods?*

  - *Variabilities can exist with both core and log data due to the age of the information, existing technology when data was acquired, experience and quality of the service company, handler/logger errors, differences in resolution of the data, and digitization of paper logs. These variabilities are within the standard level of uncertainty and are addressed in the core to well calibration.*

EPA Evaluation of Response: The answer is responsive in acknowledging the sources of uncertainty. It does not, however, provide a general estimate of how large the errors might be and how the core to well calibration helps in addressing the uncertainty.

Follow-up Questions/Requests for CES:

- In cases where there is less agreement between the cores and low-based estimates, is the core data considered authoritative? Are there concerns about bias in the core data (e.g., due to heterogeneity in the formation or possible damage to cores during drilling)? If so, how will this be managed?
  - The current core data are not considered to be authoritative due to the age of the reports, the empirical permeability calculation, and the lack of any historical information on the core. It is not known how the core points were picked, taken, processed, or analyzed, thus values needed to be accepted as given. The

core values that had less agreement to the logs will be reviewed in detail with new core and log acquisition to determine whether any changes can be made to the petrophysical model to help with the log-to-core calibration or if the cores themselves are of poor quality and not a good representation of the formation.

- CES explains on page 34 of the narrative that, "Petrophysical results show a reasonable estimate of total porosity and permeability; however, there is uncertainty on the effective porosity because an empirical relationship was used to estimate irreducible water." How will the uncertainty with effective porosity be addressed?

    - With currently available log data (one porosity data point, NAPA-AVE 1, 8 miles east) there is little that can be done to decrease the uncertainty. Site-specific data will reduce overall project uncertainty. In addition, using the site-specific data, an uncertainty program will be designed to understand model sensitives in greater detail, analyzing variables such as effective porosity. When core is acquired, effective porosity (with a range of error) will be calculated via laboratory measurements.

- *Will the same method(s) be used to calibrate the core data to the well log data at the Mendota site?*

    - *In principal, the methods will be the same with comparing the core and well log data; however, at the Mendota site, additional cores and well logs will be acquired. With modern core processes and the latest logging technology, it will be possible to compare not only porosity and permeability but also mineral weights and volumes, geomechanical stresses, geochemistry, and total and effective porosity and saturations. Zone to zone adjustments will be required in the model to account for changes in the formation that are observed in the acquired core. The calibration from log to core is not made for the simple fact that the log variables must match the core variables. Physics of the inputs need to be real and not forced, meaning the model inputs must agree with each other and make sense. The calibration of the petrophysical models' outputs to the processed core variables requires an indepth knowledge of the core measurements taken and how they align to the well log data. Modern core analyses and logs will enable for a more accurate calibration between the two.*

EPA Evaluation of Response: The response is generally acceptable. We agree with the need for zone to zone adjustments and the larger suite of information that will be available with the anticipated logging and core analyses.

Regarding the primacy of core data in calibration, see our above comment/question about how any instances of poor agreement and potential bias between log and core samples will be addressed.

Please include a more detailed explanation in the updated application regarding the cores, their quality, and the laboratory results in order to clarify how robust those data will be for calibration of the log-based estimates.

- An updated, more detailed explanation of the work with core and logs will be included in the application.

- *What is the spatial resolution of the log measurements?*

    - *The vertical resolution of log data is 0.5 ft intervals. Well logs were upscaled into the geomodeled cells at 4 ft vertical resolution. Lateral resolution of geomodel cells is 500ft x 500ft in the X and Y direction.*

EPA Evaluation of Response: The response is acceptable.

7.2 Objectives for Pre-Operational Testing:

- *Gather site-specific measurements during drilling of the proposed injection well and deep monitoring well of capillary pressure, and information on fractures, stress, ductility, rock strength, elastic properties, and in situ fluid pressures within the confining zone to support an evaluation of confining zone integrity.*

- CES has the following plans for *core analyses:*

  - *Mercury injection capillary pressure*
  - *Fracture analysis/description of the whole core*
  - *Triaxial compression testing (with added stress stages and ultrasonic velocity measurements), of injection zones to measure static and dynamic elastic moduli and to calculate a mohr- coulomb failure envelope.*
  - *Multi-stage triaxial compression testing on oriented samples (vertical, horizontal and 45deg), of seal zones in order to calculate anisotropic geomechanical properties.*
  - *FIT/FIS analysis on cuttings for entire well bore on all wells in vicinity to determine preexisting communication vertically and laterally.*

EPA Evaluation of Response: The proposed core analyses are appropriate. In addition, in-situ fluid pressures will be obtained during drilling, fall-off testing, and other formation testing that will be required pursuant to permit conditions and 40 CFR 146.87.

Porosity

The average Panoche Formation porosity estimates range from 20% in the First Panoche Sand to 10% in the Fourth Panoche Sand (Table 3). Average estimated porosity in the primary injection zone, the Second Panoche Sand, is 18% (page 39). The Moreno Shale is estimated to have an average porosity of 8%.

Total porosity of the injection zone was determined from bulk density or compressional slowness (run in 5 wells to the east and southeast of the proposed injection well). The clay volume (VCL), estimated from spontaneous potential or gamma ray logs (run in 10 wells), and irreducible water were then used to estimate effective porosity; the water associated with clay minerals and irreducible water must be removed from the total porosity to estimate effective porosity. CES acknowledges that there is uncertainty in the estimated effective porosity because an empirical relationship was used to estimate irreducible water.

7.3 Questions/Requests for CES:

- *What is the empirical relationship that was used to estimate irreducible water? How much uncertainty does this relationship entail?*

  - *The empirical relationship of 20% for sandstones and 30% in shales was used as a reasonable cutoff in the model to estimate irreducible water. Irreducible water is calculated from porosity and permeability and therefore is subject to the same level of uncertainty as the porosity and permeability calculations. Further acquisition of logs and core will increase the accuracy of porosity and permeability estimates which will decrease the amount of uncertainty regarding irreducible water.*

EPA Evaluation of Response: We agree that, specific methods aside, uncertainty will be reduced with additional data. The proposed data collection described in the various responses in this document appears to be appropriate. When the application is revised, we will anticipate reviewing a description of the empirical relationship relating porosity and permeability to irreducible water and what assumptions or limitations it entails.

Follow-up Questions/Requests for CES:

- The values of 20% and 30% are specific values rather than relationships. Are these assumed to be typical values? If so, on what information are they based? Are these values believed to represent similar lithologies in the region?

- With no specific data on irreducible water, experience in reservoir modeling was used to specify values of 20% and 30%. Future irreducible water calculations will use data from logs and core to develop empirical relationships for petrophysics. These new calculations will available to help refine the simulation modeling.

  - When the permit application is revised, please provide a description of the empirical relationship relating porosity and permeability to irreducible water and what assumptions or limitations it entails.

- CES will provide in the revised application a description of the relationship between porosity, permeability, and irreducible water, including any assumptions and limitations that were used.

- *For the VCL estimates, Table 4: (Mineralogy summary from core XRD - NAPA AVE A 1; page 39) shows 10-22% potassium feldspar in the samples. Will that percentage of alkali feldspar bias the VCL values from gamma ray logs? Also, what units/depth/ were used as the reference points for clean sand and shale for the VCL estimates?*

  - *To mitigate the effect of alkali feldspar bias multiple log inputs were used to calibrate VCL. Due to the availability of digital log data SP was the primary input, calibrated to both Gamma Ray and Neutron Density. Core data was used to calibrate further in the sandstones and shales.*

  - *CES plans to perform XRD analysis on either the whole or rotary core to provide clay and K- feldspar content that can be used to calibrate the VCL estimation.*

EPA Evaluation of Response: The response is acceptable. Although it does not specify what sand and shale end members/reference points CES used in their preliminary estimates to date, CES should have the necessary data to do a refined analysis once their data collection has been done.

- *The application narrative states, on page 34, that VCL log values greater than 30% were considered to be shale and anything less than 30% VCL was flagged as sand. What is the basis for this interpretation?*

  - *A cutoff of 30% is a reasonable reference point based on VCL log estimates to analyze reservoir vs. non-reservoir thicknesses and perform preliminary fault seal analysis. Site characterization data will enable a more sophisticated facies log calculation, such as HRA (Heterogeneous Rock Analysis) facies assignment.*

EPA Evaluation of Response: The response does not provide a basis for the 30% value. However, this point may be moot as the response suggests that the HRA will enable the selection of a site-appropriate cutoff value. In the revised version of the application, please provide a description of the advantages and limitations of the HRA and the resulting facies assignments.

- *How many analyses for porosity are proposed to be performed with cores from drilling of the proposed injection well and observation well?*
  - *Two different porosity analyses are recommended to be performed on the core samples:*
    - *Basic Boyles Law helium porosity measurements within the injection zone whole core/rotary core samples, every 2-3 feet (sampling interval will depend on heterogeneity and thickness of the sandstone beds).*
    - *Tight rock analysis porosity measurements on whole core/rotary core samples from the confining zones every 5-10 feet.*

EPA Evaluation of Response: The answers are generally acceptable; see more specific comments and questions for this section.

7.4 Objectives for Pre-Operational Testing:

- *Obtain laboratory core data on porosity at the Mendota site for the injection and confining zones to confirm the representativeness of the available data from nearby oil fields, support calibration to well logging data, and support development of the porosity distribution in the geomodel.*
- *Obtain core and well log data that will help identify vertical heterogeneity inporosity.*
- *Obtain well logging data to support log-based porosity calculations and calibration to core analyses.*
- *Verify estimates of irreducible water that were presented in the permit application.*
  - *Please refer to previous responses to the objectives for pre-operational testing for details on the core and well log data to be acquired and what information will be provided by the analysis/ses performed on the core.*

Permeability

The Panoche Formation permeability estimates range from 300 mD in the First Panoche Sand to 87 mD in the Fourth Panoche Sand (Table 3). Estimated average permeability in the primary injection zone, the Second Panoche Sand, is 290 mD (page 39). The Moreno Shale is estimated to have an average permeability of 4.7 mD (page 39).

Page 38 of the application states that: "The intrinsic permeability was estimated based on the porosity and lithology of the formation (Herron, 1987) using the wells around Mendota_INJ_1 (Figure 29). The lithology model consisted primarily of Quartz, Clay and Feldspars based on the core from NAPA AVE A/1. The relationship of porosity vs permeability is show in Figure 30. The average permeability of both the injection and confining zones is shown in Table 3 and Figure 31 shows the spatial variations in permeability thickness (KH) for the different formations."

7.5 Questions/Requests for CES:

- *How many analyses for permeability are proposed to be performed with cores from drilling of the proposed injection well and observation well?*
  - *Two different permeability analyses are recommended to be performed on the core samples:*
    - *Basic steady-state gas permeability measurements on injection zone whole core/rotary core samples, every 2-3 feet (sampling interval will depend on heterogeneity and thickness of the sandstone beds).*
    - *Pulse-decay permeability measurements on whole core/rotary core samples from the confining zones every 5-10 feet.*
- *The text mentions "facies logs" (e.g., on page 40). Does this refer to the VCL data derived from the well logs?*
  - *The facies log mentioned on page 40 refers to the simple facies log derived from VCL using a 30% cutoff.*

EPA Evaluation of Responses: The responses are acceptable.

7.6 Objectives for Pre-Operational Testing:

- *Obtain laboratory core data on permeability at the Mendota site for the injection and confining zones to confirm the representativeness of the available data from nearby oil fields, support calibration to well logging data, and support development of the permeability distribution in the geomodel.*
- *Obtain well logging data to support log-based permeability calculations and calibration to core analyses.*
- *Obtain core and well log data that will help identify vertical heterogeneity inpermeability.*
  - *Please refer to previous responses to the objectives for pre-operational testing for details on the core and well log data to be acquired and what information will be provided by the analysis/ses performed on the core.*

8 Mineralogy, Petrology, and Lithology of the Injection and Confining Zones

The Panoche Formation consists of layers of deep marine shale and submarine fan deposit intervals (page 15). Although the target injection zones are the First and Second Panoche Sands at the proposed injection site, CES bases their description on a core sample from the Fourth Panoche Sand (Depth: 11,422 - 11,471 ft) taken at the B.B. Co Well 1 located 2.32 miles from the storage site. (page 64; Attachment B, page 20). The Panoche Sands contain a mixture of sandstone and conglomerate. The sandstone contains mostly coarse, poorly sorted quartz and feldspar grains, cemented by calcite. There is also an abundance of biotite with low amounts of chlorite, muscovite, and pyrite (page 64). This analysis is consistent with a sample taken from NAPA AVE A/1 located 9 miles from the site at depths between 8,200-8,751 ft, roughly correlating with the depth of the proposed injection zone (page 34).

Table 4 shows that the lithology of the NAPA AVE A/1 sample, obtained through core X-Ray Diffraction (XRD) consists primarily of quartz, clay, and feldspars (page 39). Uncertainties include lateral conformity to the site, leading to potentially different minerology and reservoir properties. CES plans to sample a core at a characterization well (page 27). CES has done initial geochemical modeling to address the potential for mineral precipitation and dissolution, with possible changes in porosity and permeability.
Future cores should include samples from the confining layers, with measurements of mineral composition.

8.1 Questions/Requests for CES:

- *The NAPA AVE A/1 sample is taken at a depth that correlates to the injection zone. On page 18, it is noted that the sand and shale facies vary in lateral extent and thickness. Is there additional evidence indicating that the injection zone sample taken from NAPA AVE A/1 is analogous to the site injection zone?*

  - *As explained in the response to a question on comparability of sandstones across the wells in the Geomechanics and Petrophysics Section 7, there is uncertainty in the depositional setting in the study area. Published reports (Hosford Scheirer & Magoon, Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California, 2007) describe a progradation from east to west from deltaic to channel and fan slope facies along the eastern edge of the basin. Based on the regional maps, written descriptions and conceptual diagrams it is likely that Panoche sandstones described for the proposed Mendota_INJ_1 well are part of the slope channel and fan complexes; however, the possibility that the well location could intersect sandstones in the more distal parts of the deltaic sequence. The USGS report states that the sandstones in these two depositional environments are coeval in which case it is reasonable to assume that the provenance for the slope channel and fan sandstones are from the deltaics up-dip. Digital log responses from 10 nearby wells show the Second Panoche Sandstone below the regionally correlatable First Panoche Shale are consistent. The sandstones in the NAPA AVE A/1 well lie on a parallel trend with Gill Ranch sandstones, which are interpreted as deltaic, and therefore are likely to be similar in depositional setting. Although the proposed injection well is more distal and possibly in the fan channel setting, the similar ages of the sandstones, their comparable log properties and expected similar petrology regardless of the depositional setting suggests a similarity in properties between wells. There are likely some property differences; however, given the greater depth of burial and expected higher compaction, in the sandstones in the proposed injection well site to the NAPA AVE A/1 well, it is not expected that these differences will be significant.*

EPA Evaluation of Response: The response is adequate given the amount of available information.

8.2 Objectives for Pre-Operational Testing:

- *Obtain core samples during drilling of the proposed injection well and deep monitoring well to characterize the mineralogy and lithologies of the injection and confining zones at the Mendota site.*

  - *Please refer to previous responses to the objectives for pre-operational testing for details on the core and well log data to be acquired and what information will be provided by the analysis/ses performed on the core.*

9 Seismic History and Seismic Risk

The Mendota site is located near the center of the San Joaquin Basin, which is less tectonically active than the margins of the basin. Historical earthquake data were obtained from the USGS Earthquake Hazards database. All earthquakes in the region since 1900 with a magnitude greater than 2.5 were taken into account. Major fault systems in the region include the San Andreas Fault approximately 40 miles to the southwest and the San Joaquin and Ortigalita fault systems approximately 15 to 20 miles to the south and west. The nearest cluster of quakes, all less than 5.0 magnitude, occur along the San Joaquin and Ortigalita faults and are shown on the map in Figure 42. The largest nearby quake was the Coalinga Quake with a magnitude of 6.7 in 1983, located approximately 36 miles south of the Mendota site (page 53). The nearest to the Mendota site were three small quakes (<3.0 magnitude) between ~2.5 to ~5 miles away; the most recent of these occurred in 1998 (Figure 43). The application states that the relative risk of the proposed site is low compared with the active zones associated with major faulting (page 53). In order to more fully assess seismic risk at the Mendota site, more information will be needed about local stresses and fracture networks (page 54).

9.1 Questions/Requests for CES:

- *The application, on page 53 states, that the "relative risk of the proposed site is low compared with the active zones associated with major faulting." Please clarify how the seismic risk profile for the site will be quantified, particularly in the context of a seismically active region.*

    - *The natural seismicity at the Mendota site is relatively much lower when compared to other regions in the San Joaquin Basin. The seismic risk profile will be quantified using historical data (from the USGS and CEMA), interpretations from the 3D seismic, wellbore FMI measurements and geomechanics measurements on whole core/rotary core samples (which can help delineate potential failure of the rock). Microseismic monitoring will also be used to first establish a baseline prior to injection and continuing during the injection period. The local stress field and fractures will be quantified using caliper logs, core and FMI interpretation collected during and after drilling. Seismic activity will be actively monitored throughout the injection period.*

EPA Evaluation of Response: This response appears to be adequate; however, the results of the evaluation CES describes will need to be reviewed prior to authorization to inject. It is assumed that this risk evaluation will be incorporated into the risk register that CES described as part of their responses to questions about the proposed Emergency and Remedial Response Plan.

EPA recommends that the evaluation address how the project:

- has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO_2 proposed to be injected.

- The interpreted faults and fractures will be described after the 3D survey and FMI data are acquired and processed. Note that only seismically resolvable faults will be interpreted. Faults below seismic resolution will remain that; below resolution. The subsurface containment system will then be compared to the position of the known fracture and fault systems and reported to the EPA to confirm the capability of the system to contain the injected CO_2.

- will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events.

- Prior to injection, a microseismic baseline is proposed to establish the background microseismicity in the area. Continuous microseismic monitoring will be performed during the entirety of the injection period. The injection pressures will be below the threshold pressure (using the fracture gradient information collected from the characterization well) at which injection would be expected to create microseismic events.

- will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and

- Continuous microseismic monitoring is the most reliable method for detecting microseismic events in real time, and the real-time component of the monitoring program will enable quick calculation of the magnitude of microseismic events. Mitigation measures from the ERRP and Risk Register will be followed immediately based on the magnitude of the event.

- poses a low risk of inducing a felt seismic event.

- Prior to injection, a microseismic baseline is proposed to establish the background microseismicity in the area. Continuous microseismic monitoring will be performed during the injection period. The injection pressures will be defined to remain below the threshold pressure (using the fracture gradient information collected from the characterization well) at which injection would be expected to create microseismic events. Although the minimum magnitude that can be felt varies based on hypocenter depth and soil conditions, microseismic monitoring and the risk mitigation measures will be implemented in a manner that takes magnitudes that can be reasonably expected to be felt into account.

9.2 Objectives for Pre-Operational Testing:

- *Incorporate geomechanical information (dipole sonic logs), formation microimager (FMI) logs, and micro-seismic monitoring into the analysis of seismic risk to inform setting of operating conditions and emergency response planning.*
  - *Please refer to previous responses to the objectives for pre-operational testing for details on the core and well log data to be acquired and what information will be provided by the analyses performed on the core.*

10 Facies Changes in the Injection or Confining Zones

The facies descriptions and depositional history as described in the permit application are consistent with the presence of interbedded shales and submarine fan deposits, including a lenticular shape for the sandstone units.

The description of the lithology from the B.B. Co 1 well is at a depth corresponding to the Fourth Panoche Sand. Figure 5 in the application narrative, however, shows the Second Panoche Sand as the primary injection formation, with the Fourth Panoche Sand as an optional formation. Given the latter, and the vertical heterogeneity inherent in a shallow marine environment with turbidites and shallow marine shale facies, the lithologic characteristics of these two sands and the surrounding shales at the Mendota site will need to be confirmed during the pre-operational testing program. This would help identify any facies changes that could provide potential preferential flow paths (i.e., high permeability zones) or otherwise affect containment and fluid movement.

CES has indicated that 3D seismic profiling and a characterization well will help in assessing the extents, thicknesses, and lithologies of the injection and confining zones.

10.1 Objectives for Pre-Operational Testing:

- *Characterize the geologic units, including the geometry, thicknesses, and extents of the sand and shale units and confirm that these are consistent with current understanding of the depositional history and facies changes expected at the Mendota site based on the 3D seismic survey.*
    - *Detailed lithologic descriptions will be collated of the slabbed whole core through the Panoche sandstone beds that will identify the vertical extent of the facies and facies changes. The core data and log data will be incorporated with 3D seismic interpretation to determine the geometry, thickness and the extent of the facies.*
- *Determine if there are any heterogeneities within the Second Panoche Sands that could affect its suitability for injection, including facies changes that could facilitate preferential flow.*
    - *The tools described above will address this requirement.*
- *Collect seismic, core, and well logging data that will support characterization of subsurface heterogeneity and refinement of a refined geomodel.*
    - *Please refer to previous responses to the objectives for pre-operational testing for details on the core, well log and 3D seismic data to be acquired and what information will be provided by the analyses performed on the core.*

EPA Evaluation of Responses: The responses are acceptable.

11 Structure of the Injection and Confining Zones

The Panoche Formation and the Moreno Shale formations were deposited at the same time as the Great Valley deposits in the east and pinch out against basement rock to the east as shown in Figure 3 and Figure 4 (Bartow, 1990) (Scheirer, 2003). It is difficult to confirm the pinch out as a sealing factor from Figure 4 (page 16). CES states that models of depth, thickness, and areal extent of the injection and confining zones were created using well and 2D seismic data that were incorporated into a geomodel in Petrel (page 33). Future cross sections should show an aerial view with transects labeled.

The current information on the general geometry of Fault 13 is shown in Figure 22. There are, however, uncertainties regarding its characteristics (e.g., displacement, sealing capabilities). CES plans to clarify the fault's location and characteristics.

CO_2 plume simulations show the plume migrating up-dip to the northeast, away from Fault 13 (page 27). The regional dip of this and other formations is noted as being about 4 degrees to the southwest (page 18; Figures 16 and 17). On page 71, however, the text states that "...The regional dip of this [the Panoche] and other formations is to the northeast; this implies that the injected CO_2 will migrate approximately 2 miles to the northeast (Section 3)." The text on page 71 may be in error as it is inconsistent with other sections of the text and with the figures and cross sections.

11.1 Questions/Requests for CES:

- *Please clarify if the text on page 71 regarding the dip to the NE is in error as it is inconsistent with discussion in other sections and with several figures.*
    - *This was an error; the text should state that the stratigraphic beds dip southwest towards basin axis.*

- *What are the primary mechanisms for lateral confinement? Is it based solely on sand pinch out? If so, please provide evidence to confirm the pinch out as a sealing factor (as this is not entirely clear in Figure 4).*
    - *The primary mechanism for lateral confinement based on the dynamic modeling is post-injection, buoyancy and capillary forces stabilizing the injected CO_2 plume over time. This process does not require a physical low permeability lateral barrier up-dip. Regional mapping indicates lateral stratigraphic pinch outs are likely in up-dip shales from the proposed injection site providing a secondary lateral seal. This assumes that the sandstones in the injection well are related to the channel/fan complexes on the Cretaceous slope. As explained previously, there is some uncertainty in the depositional setting as the proposed reservoir sandstones could be part of the distal deltaic sequence. Figure 2, for example shows several conceptual depositional models for the Cretaceous facies distribution from the northern San Joaquin basin with the distal Lathrop sandstones (likely first and second Panoche) pinching out in the Moreno Shale up-dip, which are likely basin floor fans. Channelized sandstones feeding the basin floor fans are further up-dip across the Cretaceous slope with much of their lateral margins encased in shale. The site of the injection well is likely in this up-dip part of the channel sandstone complex; however, due to uncertainty in the regional interpretation it is possible that the targeted sandstones are part of the distal deltaic Starkey sandstones up-dip or that slope channels connect creating a connected permeable sandstone pathway. Because of this uncertainty a conservative approach has been taken for geomodeling with sandstones mostly homogenous and connected throughout the model. Using this approach dynamic modeling results show that the plume is constrained by in-situ capillary controls. During injection, pressure gradient is the most significant factor to determine the lateral and vertical migration. Sequence stratigraphy and lateral confinement will be better understood once 3D seismic data is acquired and lithocube analysis performed.*

- *To what degree are the faults expected to affect lateral confinement?*

- *Preliminary fault seal analysis shows that displacement across Fault 13 is low, indicating that potential for communication between sandstone zones (stratigraphically separated by shales) is unlikely. Additional fault interpretation using 3D seismic data and modern pressure data will help determine whether faults exist in the AoR and if they will affect lateral confinement.*

EPA Evaluation of Responses: The responses in this section are acceptable. We understand that SCAL will be done to better constrain relative permeability and capillary pressure.

11.2 Objectives for Pre-Operational Testing:

- *Verify fault locations and sealing properties based on the results of the 3D seismic survey.*
  - *A 3D seismic survey will be acquired to verify fault locations, the extent of faulting, and the sealing properties. Sealing properties will be estimated from fault seal analysis using techniques such as shale gouge ratio.*
- *Confirm the lateral thickness and homogeneity of injection targets.*
  - *The lateral thickness and homogeneity of the injection targets will be confirmed upon acquisition of 3D seismic, well log and core data.*

EPA Evaluation of Responses: The responses are acceptable.

12. CO2 Stream Compatibility with Subsurface Fluids and Minerals

Section 2.8.4 (page 65) and 2.8.5 (page 66) describe the geochemical model setup and reaction path simulations that were performed to assess interactions between the injectate and the formation solids and fluids. Modeling was done using the geochemical modeling program Geochemist's workbench.

CES notes that the simulations show a net reduction of rock mass and volume. This would result in increased porosity and (potentially) permeability.

CES should update the initial geochemical modeling effort when new data on fluid chemistry and mineralogy are available from the formation testing. Potential effects of water-rock interactions on porosity and permeability may require more refined modeling and will not be fully known until the operational phase of the project.

12.1 Questions/Requests for CES:

- *Will the autoclave testing mentioned in the application or any other laboratory experiments be conducted to help refine the modeling?*
  - *Autoclave CO_2-water-rock reaction experiments can be conducted with core and water samples taken from the injections. The core samples can be analyzed before and after the experiment to quantify the effects of mineral reactions on flow and geomechanical properties. Aqueous chemistry data from the experiments will be used to calibrate geochemical modeling.*
- *Will surface area (BET) measurements be done to refine the modeling?*

- *BET measurements on the core samples is recommended.*

EPA Evaluation of Responses: The responses are acceptable.

Objectives for Pre-Operational Testing:

- *Generate fluid chemistry and mineralogic data, pressure, temperature, and pH conditions at depth via core sampling and formation testing in the characterization and monitoring wells to provide inputs to the geochemical modeling.*
  - *Various water and core analyses will be obtained to assist with the geochemical modeling.*

13. Confining Zone Integrity

The integrity of the upper confining zone (Moreno Shale) is based on the thickness and continuity of the unit from seismic and other information, the presence and properties of faults and fractures, and information on petrophysical and lithologic characteristics from available core and well log data. According to the isochore maps in Figure 13, the Moreno Shale ranges from 800-1,650 feet thick in the proposed AoR (page 40). This will be confirmed during testing.

The current porosity and permeability estimates for the Moreno Shale are 8% porosity and 4.7 mD for permeability (Table 3). The porosity appears low and the permeability appears somewhat high for a shale. These need to be confirmed with site-specific data collected during pre-operational testing. Other parameters relevant to confining zone integrity include the capillary entry pressure, which was estimated using the Van Genuchten model because of the absence of laboratory measurement (page 50). CES notes that other tests to assess confinement zone integrity include formation microimage log measurements and drill stem testing (DST) or Modular Dynamics Tester (MDT) stress testing (page 50).

13.1 Objectives for Pre-Operational Testing:

- *Confirm mineralogy, porosity, permeability, capillary entry pressure, and geomechanical properties of the Moreno Shale based on core sampling and laboratory measurements to confirm that the* Moreno Shale will retain its integrity at planned operating conditions (i.e., injection pressures).
  - *Shale petrophysical and geomechanical characteristics will be confirmed via core sampling and laboratory measurements.*
- *Obtain well log data from all shale units that can provide containment to allow log-based estimates of VCL, porosity, permeability, and TDS.*
  - *A variety of well log data will be obtained, including but not limited to Triple Combo logs (Density, Neutron, Resistivity), specialty tools to measure porosity, permeability and the amount of minerals in the formation, sampling and pressure tools, compressional and shear sonics, and borehole imaging, etc.*
- *Test for changes in capillary entry pressure due to reaction of the shale with the injectate via laboratory experiments.*

    - *Threshold entry pressure tests can be used to test for changes of the capillary entry pressure on whole and rotary core.*

- *Determine the fracture pressure of the Moreno Shale.*
    - *Because of the nature of the fracture test and to avoid caprock damage (Moreno Shale) the test is recommended to be done in the injection zone, whilst still providing valuable stress calibration point. Alternativity, this test can also be conducted in the upper portion of the Moreno Shale.*

    - *A geomechanical model with rock properties calibrated to geomechanical core test data will be used to provide an estimation of fracture pressure via the poroelastic stress equation. This is performed continuously along the well trajectory, including the Moreno Shale. The fracture pressure estimation can be further refined and validated through field test measurements such as step rate or Diagnostic Fracture Injection Test (DFIT). In both cases a limited small volume offluid is injected into the rock volume to initiate and propagate a small fracture which then closes as the pumps are turned off. The closure pressure of the fracture is a direct measurement of the fracture pressure and can be used to validate the fracture pressure profile estimated from the poroelastic stress equation.*

EPA Evaluation of Responses: The responses above are acceptable.

ENCLOSURE 2

Evaluation of Applicant Responses to EPA's Technical Review Comments on the Proposed Emergency and Remedial Response Plan and Financial Responsibility Cost Estimates in the CES-Mendota Class VI Permit Application

EPA reviewed responses provided by Clean Energy Systems (CES) to EPA's questions about the CES-Mendota Class VI UIC Permit. EPA's Technical Review Comments and recommendations (dated October 1, 2020) are in black or blue text. The applicant's responses (dated November 2, 2020) are provided in green text. EPA evaluations are in red text. EPA expects that most of these questions can be answered based on available information and requests that they be addressed in the updated permit application that CES plans to submit later in 2021. However, where applicable, EPA notes below that some cannot be fully addressed until the well is constructed and pre-operational testing is performed. No confidential business information is included in this document.

Emergency Identification and Response Actions

For a holistic documentation of the response, EPA recommends that, for each scenario, the following be identified: severity of the impact: (i.e., high, medium, low); likelihood of the event; timing of the event (i.e., project phase); avoidance measures in place to reduce the likelihood of the event (e.g., maintenance or monitoring); detection methods that reflect planned testing and monitoring; response personnel; and equipment.

A separate risk register has been created that encompasses the recommended content listed above. The scenarios defined in the risk register align with what was initially defined in the proposed Emergency and Remedial Response Plan (ERRP) and incorporates EPA's recommendations, including additional scenarios that expand upon equipment failure.

The likelihood and severity were defined based upon knowledge of the area, previous project experience, and domain knowledge. A meeting was held amongst the team where consensus was reached as to the likelihood and severity levels. As the project progresses, the risk register will be updated to reflect the current risk scenarios and incorporate residual risk based upon the response plan.

The risk register, along with an updated ERRP is included in the Appendix.

EPA Evaluation of Response: The risk register appears to be comprehensive, well documented, and specific to events and project conditions, which will support the permit record. A few comments are provided:

- Project phase: EPA suggests that these align to Class VI project phase terminology (i.e., pre injection, injection, post-injection) for consistency with other attachments.
- Severity: Not all-natural disasters would necessarily be catastrophic or have catastrophic effects on the project (although all must be investigated/addressed as described).
- Avoidance measures: EPA suggests that these focus more on planned USDW protection activities, e.g., injection within permitted pressure/rate limits; well maintenance, testing, and facility safety measures; alarm and shutdown systems. (This would be N/A for natural disasters.)
- Equipment: For the fluid leakage, natural disaster, and seismic event scenarios, response equipment may also include well repair equipment (e.g., workover rigs) to address potential damage to the injection or monitoring wells.

To make the Emergency and Remedial Response Plan document (which would be attached to the UIC permit) more comprehensive and consistent with the risk register, EPA recommends that certain information from the risk register be incorporated into the plan document. For each emergency event in the plan, please include individual sections that describe:

- Severity;
- Timing of event;
- Avoidance measures;
- Detection methods (from the "Risk Triggers" column in the risk register);
- Potential response actions (as presented in CES's current draft);
- Response personnel; and
- Equipment.

Note that EPA has recently updated the E&RR Plan template to add these sections. It is available in the Project Plan Submissions module of the GSDT; please use this new template.

- CES has downloaded the new E&RR Plan template from the GSDT and has updated accordingly with the content as requested above. It can be found in Appendix B below.

EPA also recommends some additions/revisions to the descriptions of response actions for the specific scenarios identified in the plan. These are summarized in the table below:

- *A column entitled "CES Response" has been added to the table below to ensure that the EPA's comment/recommendation has been addressed by incorporating into either the ERRP and/or the risk register.*

EPA Evaluation of Response: See the far-right column in the table below.

Regarding the request to explain how the selected seismic thresholds are considered to be protective of USDWs, EPA requests (brief) threshold-specific justifications to support its documentation that the project addresses seismic threats that could endanger USDWs. For example, why events in the green category are not anticipated to affect well integrity or affect containment (and require minimal response), while orange or magenta-level events necessitate a more complex response.

- The effects of microseismic events on well integrity and containment are difficult to determine with our current understanding of the faulting, fracturing, and geomechanics of the subsurface.
- After CES acquires and processes the 3D seismic survey and FMI data in the characterization well, a much clearer understanding of the positions of the faulting and fracturing in the subsurface will be established. The positions of faults and fractures will be combined with the geomechanical information generated from the downhole logging program and core analysis to generate a 3D geomechanical model of the subsurface.
- Using the results of the geomechanical model, CES will determine if the current thresholds are appropriate for the categories currently proposed for the site. If CES believes the thresholds can be appropriately tuned to site-specific conditions, more appropriate thresholds will be suggested (in coordination with EPA) for seismic events, and site-specific color categories will be assigned.

EPA also reviewed other revisions to the E&RR Plan text and offers these minor comments:

- On page 8, we suggest that Section 4.1 references risk register scenario 1 to be consistent with other references from the E&RR Plan to the risk register.

- On page 8, should "cease operations" be part of the response actions?
- On page 11, second bullet, the text "electrical malfunctions without endangering a USDW, repair faulty components" appears twice.
- On page 14, second bullet under minor emergency, we suggest the response to a loss of MI refer to the "immediate shutdown plan" to differentiate from the third bullet.

Event/Scenario	EPA Comment/Recommendation	*CES Response*	***EPA Review***
All	Add: "Limit access to wellhead to authorized personnel only." This will be added to section 4.1 and the magenta and red levels of the seismicity table	*Incorporated*	***Included for sections 4.24.5; please add this to section 4.1 and the magenta and red levels of the seismicity table*** Noted. ***In section 4.2, this should be under the response action, not the description of the scenario***
Well Integrity Failure	Response actions could also include: "If a shut off is triggered by mechanical or electrical malfunctions without endangering a USDW, repair faulty components."	*Incorporated*	***Addressed***
Injection Well Monitoring Equipment Failure	Expand this scenario to include other equipment failures and damage to the wellhead.	*Incorporated. Please refer to risk register.*	***Addressed***
Injection Well Monitoring Equipment Failure	Response actions could also include: • Evaluate the cause of the failure, and mitigate if necessary (i.e., repair equipment). • If there is damage to the wellhead, repair the damage and conduct a survey to ensure wellhead leakage has ceased. • Confirming well integrity prior to restarting injection will be part of the response for major and minor emergencies (upon approval of the UIC Program Director).	*Incorporated*	***Addressed*** ***Addressed*** ***Suggest that "Confirm well integrity..." be part of the response to major and minor emergencies***
Injection Well Monitoring Equipment Failure	Response actions for a Major or Serious emergency could also include: • Review downhole, wellhead, and annulus pressure data. solate the nearby area, if needed; establish a safe distance and perimeter using a handheld air-quality monitor. • Perform a well log/MIT to detect CO2 movement outside of the casing.	*Incorporated*	***Addressed***
Potential Brine or CO2 Leakage to USDW	This scenario should encompass: any evidence of CO2 or fluid movement out of the injection zone (i.e., not necessarily to a USDW) to address unanticipated events associated with faults or other pathways; any potential USDW endangerment/unacceptable changes in water quality; and CO2 leakage to the land surface.	*Incorporated. Please refer to risk register.*	***Addressed***
Potential Brine or CO2 Leakage to USDW	CES should identify what types of activities they plan to perform to determine the severity of the event, e.g., sampling, pressure falloff test, Hall Plot analysis.	*Incorporated. Please refer to risk register.*	***Addressed***

Event/Scenario	EPA Comment/Recommendation	*CES Response*	***EPA Review***
Potential Brine or CO2 Leakage to USDW	Other appropriate steps may include: • Address a well integrity issue, including taking specific steps to identity the location of the failure/leak, affect repairs, and demonstrate MI. Isolate the nearby area, if needed; establish a safe distance and perimeter using a handheld air-quality monitor. Brine leakage will be monitored via pressure sensors at the surface and periodic visual inspections.	*Incorporated*	***Addressed (there are a few typos in the added text, however)***
Natural Disaster	Add to the responses to a minor emergency: "If there has not been a loss of mechanical integrity, initiate gradual shutdown."	*Incorporated*	***Addressed***
Induced Seismic Event	This section and the title should refer to induced or natural seismic events.	*Incorporated*	***Addressed***
Induced Seismic Event	Please explain how the selected seismic thresholds (i.e., magnitude, distance from the project) are considered to be protective of USDWs.	*With an event inside the plume > 2, (or more than five > 1.5 in 30 days), the site operator will stop injection and run a pressure fall-off test to determine if containment has been breached.*	***Additional information is requested (see above)*** Please see the discussion of microseismic modeling at beginning of this section.
Induced Seismic Event	In the green operating state: add "Document the event for reporting to EPA in semiannual reports."	*Incorporated*	***Addressed***
Induced Seismic Event	At the yellow, orange, and magenta operating states, add: "Initiate gradual shutdown of the well if it is determined to be appropriate."	*Incorporated*	***Addressed***
Induced Seismic Event	Recommended edits to item 6 of the magenta and red operating states: • Determine if leaks to ground water or surface water or a CO2 leak to the surface occurred. • If a CO2 leak or USDW contamination/endangerment is detected: a. Notify the UIC Program Director within 24 hours of the determination and implement appropriate remedial actions in consultation with the Director.	*Incorporated*	***Addressed***
Induced Seismic Event	Please describe the "rate reduction plan" in the response to the magenta operating state. Does this refer to gradual shutdown?	*The rate reduction plan is the same as gradual shutdown.*	***Addressed***
Induced Seismic Event	In the red operating state, item 1: "Initiate immediate shutdown plan."	*Incorporated*	***Addressed***

Response Personnel and Equipment

- Is the phone number for the control room technician on duty a 24-hour number? If not, please provide one.

Yes, the phone number for the control room technician on duty is a 24-hour number.

EPA Evaluation of Response: Response is acceptable. EPA recommends that CES note that this is a 24-hour number in future revisions to the plan.

- Please include contact information (name, 24-hour number, and email address) for the plant manager.

Plant Safety Manager - Clint Cooper: Off: (559) 655-3947, 24 hr: 559-916-2139

EPA Evaluation of Response: The contact was added to the plan; response is acceptable.

Staff Training and Exercise Procedures

- Please provide a copy of CES's site specific standard operating procedures and training program

Site specific standard operating procedures (SOPs) and training programs are still under development for the Mendota Project. They are being built upon those for the existing, idled biomass power facility. When operational, the power plant had nearly 100 SOPs and 50 safety procedures. The facility earned "STAR" status from the California Division of Occupational Safety and Health (Cal/OSHA) under the Voluntary Protection Program (Cal/VPP) - a program designed to recognize employers and employees who have implemented safety and health programs that go beyond minimal Cal/OSHA standards and provide the best feasible protection at the site[1]. CES expects to continue the commitment to safety and employee participation in order to maintain leadership in the field of workplace safety and health.

For reference only, CES has included in the Appendix the Employee Safety Orientation and Emergency Action Plan for the idled biomass power facility. Note these will be updated for the Clean Energy Systems carbon capture and storage facility.

CES is working with Schlumberger on the design and development of the CO2 storage well. If Schlumberger is awarded the work, standard health, safety, and environment (HSE) practices will be applied as well as SOPs and training programs. For reference, a copy of the Project HSE Management guide describing the necessary governance documents is included in the Appendix, as well as a Standard Personnel Certification for integrated well construction (IWC). Additional information such as: Casing and Corrosion Log EMITXLD Service Delivery FE FS SWI, Wireline Cased Hole Fluid and Pressure and Testing Standard Work Instruction and Wireline Pulsed Neutron Operations, is available upon request.

EPA Evaluation of Response: Response is acceptable.

- Will the ERRP be incorporated into a site safety plan as well? If so, please include.

Yes, the ERRP will be included in the site-specific safety plan. As noted above, the site-specific plans are still under development but a sample of the idled biomass power facility's Emergency Action Plan is included in the Appendix for reference only.

EPA Evaluation of Response: Response is acceptable.

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[1] State of California Department of Industrial Relations, Cal/OSHA, California Voluntary Protection Program, https://www.dir.ca.gov/dosh/cal vpp/cal vpp index.html, accessed October 30, 2020

Financial Responsibility

CES is still working to update cost estimates for the identified FR activities and subsequently secure qualifying financial instruments. So, preliminary responses only are provided herein. CES expects to complete its estimates in the fourth quarter of2020 and resubmit FR documentation at that time. We appreciate your understanding and willingness to work with us on this matter.

This Enclosure has been abbreviated to only contain preliminary responses to EPA's Questions/Requests and Future Considerations.

PART 1: Cost Estimate Evaluation

Questions/Requests for CES:

- *It appears that CES's cost estimates were generated using the EPA FR Cost Estimation Tool; if this is the case, can CES confirm that all of the activities planned for post-injection site care and site closure, and emergency response are addressed in the cost estimate? (It is assumed that corrective action and injection and monitoring well plugging activities will be similar to the activities on which the Cost Tool assumptions are based.)*

Yes, the cost estimates submitted with Attachment H: Financial Assurance Demonstration were generated using the EPA FR Cost Estimation Tool. To the best of our knowledge, it included all planned activities for post-injection site care, site closure, and potential emergency responses.

EPA Evaluation of Response: Response is preliminarily acceptable. When CES provides specific cost estimates, EPA requests that the estimates be documented and as detailed as possible to afford a comparison to the Cost Tool-generated estimates for each activity for which financial responsibility is required.

- *The cost estimates should represent costs for an independent third party to perform each activity (i.e., not a "discounted" rate provided to CES or its consultants). Please confirm that the cost estimates provided are for an independent third party to conduct the activities described in the corrective action, plugging, post- injection site care and site closure, and emergency and remedial response plans of the permit application. Alternatively, if the estimates provided do not represent costs for an independent third party to conduct these activities, please revise and resubmit the estimates accordingly.*

CES is working with Schlumberger to develop updated the cost estimates for the identified FR activities: performing corrective action on deficient wells in the area of review (AoR), plugging the injection well, postinjection site care (PISC) and site closure, and emergency and remedial response (E&RR). Data is being gathered from third parties and Schlumberger Oilfield Services for actual 2020 costs for several items. The cost estimates represent competitive quotes for the services listed, where applicable; i.e. not a "discounted" rate. Once complete, CES will updated and re-submit the estimates accordingly.

EPA Evaluation of Response: This approach is acceptable; EPA will review the cost estimates when they are provided.

- *Please provide the date of the cost estimate and revise the cost estimates to reflect current year (i.e., 2020) dollars.*

Updated cost estimates are being developed based upon the current year and will be provided in 2020 USD.

EPA Evaluation of Response: Response is acceptable.

Future Considerations Based on the Results of Pre-Operational Testing/Modeling Updates:

- *Confirm assumptions about the depth and diameters of the injection well and monitoring wells based on final plans/as-built specifications.*

The current plan provides the best estimate based upon available information. As additional site- specific information is acquired, plans/assumptions will be updated accordingly. As built specifications will be completed when the well is drilled.

EPA Evaluation of Response: Response is acceptable; revisions to the cost estimates based on the final construction of the injection and monitoring wells may be needed prior to EPA's authorization of injection.

- *Changes to various Cost Tool inputs (e.g., the size of the AoR based on final modeling, the total volume of CO_2 to be injected, corrective action needs at the time the permit is issued, and the approved post-injection site care timeframe) will affect the estimates generated by the Cost Tool.*

Understood. Outputs from the Cost Tool can be recalculated once information is acquired based on the key site-specific data.

EPA Evaluation of Response: Response is acceptable; revisions to the cost estimates may be needed based on the final approved AoR delineation, post-injection site care timeframe, and operating plans. Updated estimates and funding of the financial instruments in part will be needed before EPA authorizes construction of the injection well. Final estimates and funded financial instruments will be needed before EPA authorizes injection.

- *Although CES provided ranges of cost estimates, the selected financial instrument(s) (see Part 2 below) will need to have a specific face value that is proposed to, and approved by, EPA.*

Understood. Once updated cost estimates are complete, CES will secure appropriate financial instruments with a set value and submit to EPA for approval. Cost estimates, and potentially the value of the associated financial instrument, may be updated once key site-specific information is acquired.

EPA Evaluation of Response: Response is acceptable. The final instrument value for each covered activity will be determined at a later date, as additional information is collected during pre-operational testing.

PART 2: Financial Instrument Demonstration

CES plans to use a single financial instrument to cover the costs of corrective action, injection well plugging, PISC and site closure, and emergency and remedial response. Financial instruments that CES identifies as under consideration include a trust agreement, escrow agreement, or certificate of insurance.

CES must provide acceptable FR instrument(s) listed under 40 CFR 146.85(a)(1) prior to the issuance of a permit for the construction of a new Class VI well. If CES elects to use a trust fund or escrow account, the EPA Director may allow phased pay-in for these two instruments. However, CES must submit a pay- in schedule for the Director's review and approval.

CES is still in the process of evaluating and securing acceptable financial instruments to support Class VI well

FR. Currently, CES is considering multiple instruments including surety bonds, letter of credit, certificate of insurance, corporate guarantees, escrow account and/or trust fund. CES may elect to use more than one financial instrument to meet the required FR demonstration. Also, based upon the project timeline, CES may implement the selected instruments at different stages of the Project and/or utilize a phased pay-in (trust fund or escrow account). We would like to work with the EPA to ensure the selected instruments and their implementation meet the requirements of the 40 CFR 146.85.

As an indication of our progress, a Letter of Support from an insurance provided is included in the Appendix. However, feedback from discussions with multiple insurance companies has indicated that no insurance policy for CCS projects yet exists. Generally, the market appears to still be in the process of evaluating risks and developing policies for CCS projects - though no guarantee has been made that such policies will be offered.

EPA Evaluation of Response: Response is acceptable. EPA understands that CES is working to secure financial instruments and will review the draft instrument(s) and any proposed pay-in schedules when they are provided.

ENCLOSURE 3

Evaluation of Responses to EPA's Technical Review Comments on the Proposed Operating Conditions and AoR Delineation Modeling in the CES-Mendota Class VI Permit Application

EPA reviewed responses provided by Clean Energy Systems (CES) to EPA's questions about the CES-Mendota Class VI UIC Permit. EPA's Technical Review Comments and recommendations (dated October 7, 2020) are in blue text. CES's responses (dated November 9, 2020) are provided in green text. EPA evaluations and follow up questions are provided in red text. EPA expects that most of these questions can be answered based on available information and requests that they be addressed in the updated permit application that CES plans to submit later in 2021. However, where applicable, EPA notes below that some cannot be fully addressed until the well is constructed and pre-operational testing is performed. No confidential business information is included in this document.

Evaluation of Operating Procedures of the CES-Mendota Permit Application

This evaluation for the proposed Clean Energy Systems (CES)-Mendota Class VI geologic sequestration project summarizes the evaluation of proposed operating procedures and data submitted by CES in Attachment A to their Class VI permit application, per 146.82(a)(7),(9),(10) and 146.88. Note that this evaluation of the proposed operating conditions, particularly injection rates and pressures, was performed in conjunction with EPA's evaluation of CES's AoR delineation modeling (see Enclosure 2).

The proposed injection well operating conditions are summarized in Attachment A (the Table), as excerpted below.

PARAMETER/ CONDITION	LIMITATION or PERMITTED VALUE
Maximum Injection Pressure - Surface	2026 psig
Maximum Injection Pressure - Bottomhole	5677 psig
Annulus Pressure	2126 psig
Annulus Pressure/Tubing Differential	100 psig
Maximum CO_2 Injection Rate	958.9 tons/day

The proposed operational procedures are also summarized in Table 20 of the Narrative, which is replicated below:

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
Surface	2026	Psi
Downhole	5677	Psi
Average Injection Pressure		
Surface	1042	Psi
Downhole	4212	Psi
Maximum Injection Rate	958.9	tons/day

Average Injection Rate	958.9	tons/day
Maximum Injection Volume and/or Mass	350000	tons/year
Average Injection Volume and/or Mass	350000	tons/year
Annulus Pressure	1142	Psi
Annulus Pressure/Tubing Differential	100	Psi

1.1 Injection Pressure

The basis for the proposed maximum injection pressure is described in Attachment A and excerpted below.

> " *The maximum injection pressure predicted at this pre-construction phase, which serves to prevent confining-formation fracturing, was determined: using the fracture gradient obtained from initial reservoir and geomechanical models multiplied by 0.9, per 40 CFR 146.88(a). An update to maximum injection pressure and rate will be provided once a characterization well is drilled and reservoir and geomechanical models are updated with site specific properties.*"

In the Narrative, Section 7.0, second paragraph, page 85, CES notes that:

> *"For the pre-construction phase the fracture pressure at the center of perforations is estimated to be **6,308 psi** at 9,705ft bgs using a gradient of **0.65 psi/ft**. A safe formation injection pressure of 90% of the fracture gradient would be __**5.677 psi**__. The surface injection pressure equivalent for the safe formation injection pressure assuming a **0.376psi/ft gas** gradient (more accurate information will be gained during operation with comparison of downhole and surface sensors) would be __**2.026 psi**__. injection pressure to reach the 90% fracture gradient of **5,677psi** at the perforations downhole. This may change as more information is gained during the evaluation phase of the well's geophysical properties during the drilling of the characterization well.*"

Furthermore, in the Narrative, Section 7.1, first paragraph, page 86, CES notes that:

> *"The maximum safe bottom-hole pressure was specified as 90 percent of the rock's fracture pressure **(0.9 x 0.65psi/ft = 0.585psi/ft)** at the depth where the CO2 is injected. For conservatism, the required injection pressure was calculated based on the assumption that the required bottom-hole pressure is equal to the maximum safe bottom- hole pressure. Maximum bottom-hole injection pressure (injection depth x 0.585 psi/ft)."*

In Section 7 of the Narrative, it is not clear how CES derived or referenced the gas gradient of 0.376psi/ft (on page 85), nor how CES has calculated the equivalent surface pressure of the maximum injection pressure of 2,026 psi.
The gradient of 0.65 psi/ft is referenced from various research papers (as noted in Attachment B, on page 17). See the AoR modeling evaluation for a discussion. The 90 percent safety factor used in Section 7 of the Narrative is consistent with the Class VI Rule at 40 CFR 146.88(a).

Questions/Requests for CES:

- Please reference the source of the gas gradient of 0.376psi/ft and/or explain its derivation.
  - *A gas gradient of0.376psi/ft was calculated using a steady state multiphase simulation software by using a flow of958.9 tons per day in a 3-1/2 inch tubing with a 2.992 in internal diameter.*

EPA Evaluation of Response: The response needs additional clarification. The type and name of the steady state multiphase simulation software has not been provided.

Follow-up Question/Request for CES:

- Please describe in the updated permit application (submitted prior to construction authorization) and provide the type and name of the steady state multiphase simulation software used to determine the gas gradient of 0.376 psi/ft.

  - The PIPESIM* steady-state multiphase simulation software was used for the flow simulation within the wellbore. This information will be added in the updated permit application.

- Please explain the basis for the calculation of the equivalent surface pressure of the maximum injection pressure at 2,026psi.

  - *The calculation was made using a steady state multiphase simulation software, to obtain the gas gradient for flowing CO_2 in 3.5-in. tubing to the mid-perforation depth of9,705ft with a maximum pressure of5,677psi. A gas gradient of 0.376 psi/ft was established by the steady state multiphase simulation software. From this, the wellhead pressure of2,026psi was derived.*

The calculation used to obtain the surface pressure is:

Maximum surface pressure flowing ***= Safe bottomhole pressure flowing - (Gas Gradient * Mid-perforation depth)***

Maximum surface pressure flowing ***= 5,677psi - (0.376 psi/ft * 9,705 ft)***

EPA Evaluation of Response: The response is acceptable. Please see the comment above regarding the gas gradient derivation.

- Please describe standard operating procedures to ensure the maximum injection pressure will not be exceeded.

  - *Downhole temperature and pressure along with surface flow or mass movement, will be monitored frequently in real time at regular intervals (e.g., 1 sample/10 second rate) which will be established closer to the completion of the well. Data will be collected in an automated control system and monitored by control software that will have established thresholds for maximum injection pressure. If a threshold is exceeded, the software will issue visual, audio and digital alerts. If required, based on alert, an automatic shutdown process for the appropriate equipment will commence until the cause for any exceeded threshold is ascertained and the required corrective measures are implemented. Depending on the required time response to correct the situation the CO2 flow rate may be reduced, or CO2 equipment can be shutdown. System and software for monitoring will be established upon completion of the well.*

EPA Evaluation of Response: The response is acceptable.

1.2 Annulus Pressure and Annulus/Tubing Pressure Differential

As indicated in the Table in Attachment A, the annulus pressure has been calculated as the required **100 psig** differential between the tubing and the annulus, plus the max injection pressure of 2026 psig resulting in a pressure of **2126 psig**. In contrast, in Table 20 on page 88, of the Narrative, the annulus pressure is listed as **1142 psi**. As noted in the evaluation of the testing and monitoring plan, it appears that the annulus pressure of **2126 psig** is **higher than** the range of pressures, of **1100 psi to 1200 psi**, to be maintained in the annulus pressure monitoring system described at the bottom of page 14 of Attachment C. However, the annulus pressure of **1142 psi** listed in Table 20 of the Narrative **does** fall within the range of pressures maintained in the proposed monitoring system.

Based on a review of the collapse pressure of the injection tubing (at 10,540 psi from Table 3 of Attachment G), and the burst strength of the casing (within the range of 2440 and 12830 psi from Table 2 of Attachment G), the annulus pressure of 2026 psi is consistent with the Class VI requirements. Please see Tables 2 and 3 below.

Tubing specifications (Table 3 of Attachment G)

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst Strength (psi)	Collapse Strength (psi)
Injection tubing	9430	3.5	2.992	9.2	L80Crl3	Long	10160	10540

Casing specifications (Table 2 of Attachment G)

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	86	22	21	19741	B	Welded	26.13	2440	1950
Surface	1800	16	15.01	84	N80	Long	26.13	4330	1480
Intermediate	7432	10.75	*9.760*	55.5	N80	Long	26.13	*6450*	4020
Long-string	7332	*7*	5.920	38	T-95 Type 1	Long	26.13	12830	13430
Long-string	10412	*7*	5.920	38	TN 95Cr13	Long	14.92	12830	13430

Questions/Requests for CES:

- Please explain the differences in the annulus pressures listed in the Table in Attachment A and in Table 20 from the Narrative. Please explain how each value was determined.
  - *Data for the annulus pressure in both tables are incorrect. The annulus pressure should be generated by a CO2-inhibited fluid of a density of approximately 11.45 ppg to 9,702ft to a pressure above the packer of5,777psi. This will deliver a positive pressure of 100 psi above the packer with a 5,677-psi injection pressure. Attachment A: Summary of Requirements Class VI Operating and Reporting Conditions table and Table 20 in the Class VI Permit Application Narrative 40 CFR 146.82(a) will be updated accordingly. Please refer to Appendix A for updated tables.*

EPA Evaluation of Response: The updated table in Appendix A includes the revised annulus pressure of 5,777 psi as noted; this pressure is below the reported burst strength of the tubing and the collapse strength of the casing. The response is acceptable.

• Please describe standard operating procedures to ensure the maximum annulus pressure will not be exceeded.

- *Surface wellhead and downhole conditions will be monitored continuously for pressure. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum allowable pressures. These thresholds cannot be established until the well is drilled and analysis of the formation is performed and understood. After a threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate pressures. Typically, a list of options will be provided to the operator as to what could cause a high-pressure event. Shutdown will need to be gradual so that monitoring of the pressures and changes can be evaluated to determine if there is impact to the well or formation. Depending on the scenario, it may be necessary to vent well fluids to a predetermined safety location. This option would be considered as a process of last resort in maintaining pressures inside the wellbore's specifications.*

EPA Evaluation of Response: The response is acceptable.

1.3 Maximum CO_2 Injection Rate

CES proposes a maximum daily CO2 injection rate of 958.9 tons per day, which equates to 350,000 tons/year (or 4.2 million tons over 12 years or 7 million over 20 years). See the modeling evaluation report (Enclosure 2) for additional discussion.

Questions/Requests for CES:

• Please describe standard operating procedures to ensure the maximum daily injection rate will not be exceeded.

- *Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate. These thresholds cannot be established until the well is drilled and analysis of the formation performed and understood. After a threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation must be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.*

EPA Evaluation of Response: The response is acceptable.

1.4 Automated Shutdown System

According to Section 7, page 85, of the Narrative, CES plans to connect the information system collecting data from the pressure, temperature and mass flow gauges/sensors with automatic controls "to assist with shut down or flow controls if certain critical parameters are reached such as Maximum Flow Rate, or Pressures and Temperatures at surface and downhole..." CES notes the automatic control system is
not yet defined, as more details are needed to properly implement." This system will be evaluated when CES provides additional information.

Questions/Requests for CES:

- Please include standard operating procedures supporting the automated shutdown system when details about the system are provided.
  - *Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time at frequent rates (i.e., typically 1 recording 10 /seconds, rate not established yet). Data will be collected in an automated system and monitored by control software that will have thresholds established in it. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented. System and software for monitoring has not been established yet. Currently, data acquisition and monitoring systems are not adequately defined as to what specific procedures are followed to initiate an automatic shutdown.*

EPA Evaluation of Response: **The response is acceptable.**

Evaluation of the AoR Delineation Modeling Approach for CES-Mendota Class VI Permit Application

This area of review (AoR) delineation modeling evaluation report for the proposed Clean Energy Systems (CES)-Mendota Class VI geologic sequestration project summarizes EPA's evaluation of the modeling performed by CES as described in the Area of Review and Corrective Action Plan (Attachment B of the permit application). This review also addresses modeling-relevant site characterization information in the permit application narrative and associated files submitted to the GSDT per 40 CFR 146.84. Because they are related, this report also addresses certain elements of the proposed Post-Injection Site Care Plan (Attachment E of the permit application) that are based on the AoR modeling results. Clarifying questions for CES are provided in blue within the text below.

This report describes and evaluates how site-specific data (e.g., geologic data and planned operational conditions) described in the UIC permit application are incorporated into CES's geomodel and their computational modeling approach. Note that EPA did not perform independent, duplicative modeling of CES's AoR. Based on the breadth of currently available site-specific data and the description of the modeling effort as provided in the permit application materials, this is not warranted at this time. It is assumed that planned pre-operational testing will confirm the site characterization.

2.1 Additional Information

The EPA identified inconsistencies within Enclosure 2, which Clean Energy Systems would like to clarify below in Table 1.

Table 1: Summary of inconsistences addressed

Section	EPA Inconsistency (in Black Text)	CES Clarification
2.3	"and data for well tops obtained from California Geologic Energy Management Division (CalGEM, previously known as DOGGR), Seismic Exchange, Inc (SEI), or Information Handling Services (IHS)"	*Well tops were obtained from CalGEM and IHS.*
2.3.1	"These include the roughly 1,000 ft. thick Moreno Shale (the primary confining zone), the First Panoche Sand, the ~100 ft. thick first Panoche Shale (initial confining zone), the >1,000 ft. thick Second Panoche Sand (primary injection zone), and the underlying formations, including the 1,4002,500 ft. thick Fourth Panoche Sand (the secondary injection zone)."	*The Moreno Shale is the secondary confining zone, and the First Panoche Sand is the secondary injection interval (dissipation zone). The primary seal is the First Panoche Shale. The Fourth Panoche Sand is a potential alternative injection target, if it is present at the injection site.*
2.3.1	"The upscaled porosity and permeability graphics in Attachment B (Figures 3 and 4) would benefit from labeling for formation tops."	*The figures were updated with formation tops in Figure 7and Figure 8 (refer to Appendix A).*

Section	EPA Inconsistency (in Black Text)	CES Clarification
2.3.2.2	"based on well logs from the NAPA AVE A 1 well, about 3 mi to the east of the injection well (narrative page 51)"	*The NAPA AVE A/1 is located approximately 8.3 miles to the east.*
2.4.7.2	"Within a 2.5-mile radius"...	*A 5-mile radius was used to calculate pore volume.*
2.9.1	"CES proposed a 10-year alternative post injection site care time frame but did not provide a justification for the appropriateness of the 10-year time frame that addresses the criteria at 40 CFR 146.93(c)."	*For the pre-construction application, a 10-year post-injection was proposed based on the stabilization of simulated plume and pressure AoR within the 10-year post-injection time frame. See Figures 2 thru 7 in Attachment C: Testing and Monitoring plan for the temporal evolution of AoRs. As stated in the application, this post injection site care (PISC) time frame will be re-evaluated and updated accordingly after site-specific data are collected.*

EPA Evaluation of Response: EPA acknowledges the clarifications.

2.2 Evaluation of CES's Modeling

CES used Petrel for developing the geomodel and the ECLIPSE reservoir simulator for numerical simulations of plume and pressure front development. Petrel is a software platform that supports development of a site geomodel, allowing synthesis and 3-D visualization of data on reservoir characteristics (e.g., seismic data, structural features, well data, upscaled well properties).
Use of ECLIPSE for numerical simulations is consistent with the requirements of the Class VI Rule at 40 CFR 146.84. It accounts for the multi-phase nature of the injection activity and for the physical and chemical properties of all phases of the injected carbon dioxide (CO2) stream and displaced fluids. It allows for modeling of geochemical reactions associated with geologic sequestration of CO2. Use of these modeling programs is appropriate for simulations of plume and pressure front at a GS site.

2.3 Evaluation of the Geomodel

CES developed a geocellular model (geomodel) to support the numerical modeling using Petrel. The geomodel incorporates available data sources, including well logs from ten existing wells within several miles of the proposed injection well, 2D seismic data, and data for well tops obtained from California Geologic Energy Management Division (CalGEM, previously known as DOGGR), Seismic Exchange, Inc (SEI), or Information Handling Services (IHS). These data are synthesized to represent the subsurface system and initial conditions in a 3D grid. The geomodel for the Mendota site was used to represent the extent and thickness of the injection and confining zones with upscaled log data for petrophysical properties. Section 2.4.3 (page 39 of the narrative) states that the lateral grid resolution (cell size) for the geomodel is 400 ft. by 400 ft. CES intends to use a finer resolution for the grid when 3D seismic data (to be acquired later in the project) can be incorporated into the geomodel. Layer increments are 4 ft.

The discussion below of the site-specific parameters that CES used to build the geomodel expand on the geologic site characterization presented in the permit application narrative.

2.3.1 Representation of Site Geologic Features

The geological layering, formation thicknesses, and petrophysical properties of the project site (as described in the permit application narrative and evaluated in the geologic site characterization report) need to be integrated into a geomodel and then a numerical model domain that is consistent with available information to generate predictions of plume and pressure front movement.

The geomodel model is used to represent the depth, areal extent, and thicknesses of the injection and confining zones at the CES-Mendota site based on the site-specific data described above. These include the roughly 1,000 ft. thick Moreno Shale (the primary confining zone), the First Panoche Sand, the ~100 ft. thick first Panoche Shale (initial confining zone), the >1,000 ft. thick Second Panoche Sand (primary injection zone), and the underlying formations, including the 1,400-2,500 ft. thick Fourth Panoche Sand (the secondary injection zone). The formation thicknesses and regional dip shown in the domain for the numerical model (Model-Domain file) submitted to the GSDT are derived from the geomodel and reflect the current understanding of the Mendota site.

The porosity and permeability data from the 10 wells in the surrounding area (average values summarized in Table 3 of the narrative) were used to develop the porosity and permeability distributions in the geomodel (Figures 28, 31, and 34-39 of the narrative) from the Garzas formation down through the Precambrian basement. Visual inspection shows the values in the color legend in these figures to be generally consistent with the values in Table 3.

Figures 3 and 4 of Attachment B show cross sections of upscaled porosity and permeability distributions developed for the ECLIPSE modeling. The porosity distribution agrees well visually with the geomodel and well data.

In general, the available geologic site characterization data with respect to layering, thicknesses, and depths appear to have been rendered as faithfully as possible in the geomodel and subsequently for use in the numerical modeling (as shown in the Model-Domain file). The upscaled porosity and permeability graphics in Attachment B (Figures 3 and 4) would benefit from labeling for formation tops. It is assumed that the workflow used to generate the geomodel and numerical model domain will produce as reasonable representations of the subsurface as possible as new data become available.

2.3.2 Representation of Hydrogeologic Properties and Lithology

2.3.2.1 Porosity, permeability, and rock types

Effective porosity was determined using either bulk density or compressional slowness (from acoustical logs), combined with an estimate of irreducible water (narrative Section 2.4.2.1; discussed in the review of site characterization data). Intrinsic permeability was based on the porosity and lithology (narrative Section 2.4.2.2); CESs reference Herron (1987). The petrophysical properties (effective porosity, permeability, clay volume, and pore volume) were then upscaled from log data into 4 ft. layers along the wellbore.

- Do the permeability data represent horizontal permeability?

- *Permeability was calculated using bulk density and calibrated to core data from NAPA AVE A/1. The core data were not tested for a specific direction. For the dynamic modeling, the permeability was assumed to represent the horizontal permeability. The vertical anisotropy (kv/kh) was assumed to be 0.1.*

EPA Evaluation of Response: We have seen the assumption of a vertical anisotropy of 0.1 used in other projects; it appears to be a rough (and undocumented) rule of thumb when more specific data are not available. There are, however, no data currently presented regarding whether this assumption is valid at the CES Mendota site, nor was any literature provided in support (e.g., how commonly this value is realistic in similar lithologies and settings).

At this time, we understand that any results generated using this assumption are preliminary, and the main focus is on developing the modeling approach. A data-supported estimate of anisotropy will be needed once pre-operational testing has been done. Also, sensitivity analyses will be important to test the effects of uncertainty in the vertical permeability, especially given the buoyant nature of the CO_2 injectate and the implications for vertical migration. We have no further questions at this time but will evaluate site-specific data for horizontal and vertical permeability estimate once the application is revised based on the results of pre-operational testing.

- What method was used to upscale the petrophysical properties along the wellbores of the 10 wells for which logging data were used? How was upscaling handled for the different formations? How was the success of this method evaluated?

- *Effective porosity and permeability were upscaled using arithmetic averaging methods. Although the geometric mean upscaling method can be used for permeability, in this case, the arithmetic method was most representative of the well logs. Please refer to Figure 1 and Figure 2 in Appendix A. Layer thicknesses are constant per modeled zone.*
- *Upscaling results were quality checked using histograms and crossplots comparing the raw and upscaled data. Histograms and crossplots show a reasonable match throughout the modeled zones.*

EPA Evaluation of Response: The answer is generally responsive. We assume that the upscaling was done using the automatic process available within Petrel, which offers arithmetic and geometric averaging. The chosen upscaling method should be noted in the revised AoR and Corrective Action Plan once the pre-operational testing data are collected. Figures 1 and 2 in Appendix A are helpful in demonstrating the results of the upscaling. We encourage inclusion of similar figures in the revised plan.

- The chosen upscaling method will be noted in the revised AoR and Corrective Action Plan upon pre-operational testing data being incorporated into the model. Updated figures will be included in the revised plan.

Once upscaled, the petrophysical properties were distributed into the geomodel through Gaussian Random Function Simulation, a kriging-based algorithm (narrative Section 2.4.3). CES notes that facies logs were not used as bias in the current porosity or permeability models, but that facies biasing and Kriging to 3D seismic data will be considered in future model iterations. Figure 28 in the narrative (page 42) shows the modeled average porosity maps for each formation.

- Figure 26 in the narrative shows the net thickness maps of the Moreno Shale and First and Second Panoche Sands. The proposed injector is close to the western edge of the maps. Will the formation thicknesses further to the west of the injector be able to be represented when the 3D seismic data have been acquired?

- *Petrophysical well log data availability is limited to the east side of the model domain near legacy oilfields. 3D seismic interpretation will provide additional structure to characterize formation thicknesses to the west and south, where the current data are limited.*

EPA Evaluation of Response: The response is acceptable.

- All but one of the wells with logs used to support development of the petrophysical property distributions in the geomodel are more than 3 miles from the injector (narrative Figures 28 and 31). While crucial site-specific data will be collected when Mendota INJ_1 and OBS_1 are drilled, they will provide only two data points. How will updates to the geomodel reflect a sufficient level of detail throughout the AoR?
  - *The 3D seismic data will assist in defining the structure throughout the AoR as well as provide insight on the continuity of injection and sealing formations. Logs collected at Mendota_INJ_1 and OBS1 (and the other seven petrophysical wells where density is available) will be used for simultaneous seismic inversion and the generation of probably based lithology (sandstone, shale) cubes.*

EPA Evaluation of Response: The response is acceptable.

The graphs in Figure 30 of the narrative compare the combination of porosity and permeability of the upscaled cells and modeled cells, porosity vs. permeability by zone/formation, and porosity vs. permeability for two lithologies (sand and shale).

- In the plot of well log-derived data points, upscaled values, and full-field simulated cells, the upscaled values dominate. It appears that the upscaled value symbols may have been layered over the other symbols. Please revise the figure to show the distributions of all three types of data points more clearly.
  - *For clarity, Figure 30 has been subdivided into three figures. Please refer to Figure 3, Figure 4, and Figure 5 in Appendix A.*

EPA Evaluation of Response: The graphs have been separated as noted and are easier to review.

- Are there any concerns about autocorrelation since the permeability was based on porosity and lithology? If so, how was this issue addressed?
  - *Collocated cokriging permeability to porosity is a best practice in scenarios where calibration data are lacking. Core samples from Mendota_INJ_1 and Mendota_OBS_1 will provide a better understanding of permeability throughout the AoR. A refined facies model will provide additional and improved data for the permeability distributions and full field model population.*

EPA Evaluation of Response: The response is acceptable. We understand the model will be able to be refined once the pre-operational testing has been done and new data are available.

- How many core samples from NAPA AVE A/1 were used to support calibration between the core data and well logs?
  - *A total of 45 core samples were used to calibrate the well log to core data for the NAPA AVE A/1. Core depths range from 3,452 to 9,666 ft.*

EPA Evaluation of Response: The response is acceptable.

- In the core-to-log calibration, how was bias between core samples and well logging data handled given that cores may not capture the heterogeneity that well logging can capture?
  - *Well log data are calibrated to core by adjusting the petrophysical model to align core variables to the petrophysical model output variables. Heterogeneous biases are resolved during the petrophysical model building process by* ensuring that all existing data such as SP, resistivity, density, neutron, gamma ray, and core coincide with each other using principle component structures. Core samples are considered point data at a given depth and are used as a calibration for log models and are not an absolute. Therefore, models are never forced to match the core but rather are adjusted to obtain the best fit possible while honoring all input and output data.

EPA Evaluation of Response: The response is acceptable.

The narrative notes on page 34 that, "As shown in Table 2, some of the wells have a limited set of well log data. The petrophysical property uncertainty around these wells was reduced by calibrating parameters and multi-well comparisons across different formations."

- Please expand on the multi-well calibration described on page 34 of the narrative. Specifically, how were these data incorporated into the geomodel in a manner that is representative of the geologic system at the proposed site?
  - *The multiwell calibration begins with log input normalization. Variables are compared from one well to another as a whole and on a zone-to-zone basis. This allows the petrophysical model to be compared comprehensively, which makes it possible to determine whether an adjustment is required due to unacceptable variability. After all wells are processed, the output variables (volume clay, porosity, and permeability) are compared against each other following a similar process to that used with the input variables. Due to limited data, there is uncertainty around the geologic system at the proposed site. The proposed location is between deltaic shelf deposits to the east (Gill Ranch) and basal turbidite fans to the west (Cheney Ranch). To be conservative, the model was developed to represent a connected geologic system. Petrophysical well log data availability is limited to the east side of the model domain; therefore, it is difficult to characterize the proposed site's exact placement within the geological system. 3D seismic data will assist in refining the geologic system at the proposed site.*

EPA Evaluation of Response: The response is acceptable.

The graph in Figure 30 of the narrative showing porosity vs. permeability by formation is labeled as Z values and the legend title is "Zones."

- Please clarify the meaning of the zones in the legend of Figure 30. Are they equivalent to the formations, as suggested by the legend?
  - *Zones are equivalent to formations. For clarity, Figure 30 has been updated and divided into Figure 3, Figure 4, and Figure 5 in Appendix A.*

EPA Evaluation of Response: The response is acceptable.

- Were the data binned into zones and then associated with the specific formations? If so, please describe the method by which this association was accomplished.

- *The petrophysical characteristics (porosity and permeability) of each zone (formation) are different. Therefore, to keep these characteristics contained within each zone, the interwell interpolation of these properties was completed on a zone-by-zone basis in the Petrel* platform.*

EPA Evaluation of Response: The response is acceptable.

- Were the graphs in Figure 30 the basis for assigning phi and k in the layering in the model domain?

  - *For clarity, Figure 30 has been updated and divided into Figure 3, Figure 4, and Figure 5 in Appendix A. The graphs show the unique porosity/permeability relationships per zone. The corresponding variables were used in the layering model.*

EPA Evaluation of Response: The response is acceptable.

Figure 1 in the Rock Types file submitted to the GSDT shows rock types assigned according to porosity and log k, with the shape of data spread matching Figure 30 in the narrative. The Rock Types file indicates that data were divided into two rock types (shale and sand), and relative permeability and capillary pressure curves were assigned to the two types. The rock types were defined based on the porosity and permeability data using a neural network training method.

- Were the relative permeability and capillary pressure curves the only properties assigned based on this facies assignment and the scheme in Figure 1 of the Rock Types file?
  - *Yes, the relative permeability and capillary pressure curves were the only properties assigned based upon the facies assignment.*

EPA Evaluation of Response: The response is acceptable.

- Why was the information shown in Figure 30 of the narrative not used as the basis for assigning these curves?
  - *The facies model described in Figure 30 (updated with Figure 5) was a preliminary estimate to perform fault seal analysis. This facies log was not used as part of the petrophysical model interpolation. The rock classification methodology (neural network) was used to create the hydrofacies interpretation needed for dynamic modeling. Porosity and permeability of the geocellular model were upscaled to a tartan grid used for dynamic modeling. Please refer to Figure 6 in Appendix A.*

EPA Evaluation of Response: The response is acceptable.

- What is the uncertainty associated with the neural network training method?
  - *Neural networks estimate discrete patterns from provided input data. Unsupervised neural networks are used to subdivide the input data into several classes. This method looks for regularities or trends in the input data. In this case, two full field properties (log permeability and porosity) were the main input data. Additional input variables, if available, would strengthen the training of the neural network because permeability was estimated using porosity, both in petrophysical estimation and full field modeling. Future methodologies for rock typing/classification will include heterogeneous rock analysis*

(HRA), lithology cube analysis, and laboratory measurements.

EPA Evaluation of Response: The response is acceptable.

Figure 2 in the Rock Types file shows rock types along an E-W cross section. The cross section has two different shades of blue in addition to purple.

- Is there a difference between the two shades of blue in Figure 2 of the Rock Types file?
  - *No, the different blue shades are due to the presence of grid lines shown on the figure. Refer to Figure 6 in Appendix A for an updated version.*

EPA Evaluation of Response: The response is acceptable.

- Please label the formations in Figure 2.
  - *Refer to Figure 6 for an updated version of Figure 2 in Appendix A which includes the formation names.*

EPA Evaluation of Response: The response is acceptable.

In comparing Figure 1 in the Rock Type file with Figure 30 of the narrative, the facies in Figure 30 show a broad spread rather than the sharp dividing line in Figure 1. It appears that a number of shale data points in Figure 30 were assigned to the sandstone facies by the neural network training method in Figure 1. There also appears to be a significant difference in porosity between the Fourth Panoche and the Second Panoche Sands in Figure 30.

- Are the porosity differences between the Second and Fourth Panoche Sands sufficient to possibly warrant a third rock type?
  - *The Fourth Panoche Sandstone appears more laminated in nature than the Second Panoche Sandstone, which appears blocky or channelized and which, therefore, may exhibit differences in porosity. It is possible a third, fourth, or fifth rock type will be required to characterize all zones. After additional well log data are acquired, it will then be determined how many more rock types will be defined.*

EPA Evaluation of Response: The response is acceptable.

- Please discuss how these two methods of assigning facies were used to inform the geomodel and, consequently, the numerical model.
  - *The facies model described in Figure 30 (updated with Figure 5) was only constructed to characterize fault seal analysis; it was not used to inform the geomodel. The rock typing methodology with neural network was applied for the classification of hydrofacies (rock types) to assign relative permeability and capillary pressure functions in the dynamic modeling.*

EPA Evaluation of Response: The response is acceptable.

  - *Future iterations of facies modeling will rely on site-specific data such as wireline well logs and 3D seismic data. Wireline well logs such as density, neutron, and gamma ray, along with other processed variables, will be used to create an HRA discrete rock typing* *log. 3D seismic data and density and sonic logs will be used to create a low-frequency cube that will then inform the lithology cube analysis. This will provide a more informed understanding of the geologic system. Results of lithology cube analysis and site-specific data will determine if hydrofacies rock typing is needed for dynamic modeling.*

EPA Evaluation of Response: The response is acceptable.

2.3.2.2 Geomechanical properties

At this preliminary stage, some geomechanical properties have been assumed based on well log data from nearby wells and empirical relationships. For example, density and compressional slowness in the Moreno Shale were based on well logs from the NAPA AVE A 1 well, about 3 mi to the east of the injection well (narrative page 51). Fracturing of the formation at the project site is also unknown. There are currently no laboratory
core measurements for rock strength and ductility for the project site.

It is understood that the appropriate lab analyses will be performed on representative cores when the injection well and the OBS_1 deep monitoring well are drilled. It is also understood that borehole image logs will be acquired and used along with the 3D seismic imaging to develop a discrete fracture model.

2.3.2.3 Geomodel - 3D model grid resolution

The narrative notes in Section 2.4.3 that structural surfaces (i.e., formation contacts) were used to produce a basic framework for the geomodel. The lateral grid cell size was 400 ft. by 400 ft, but CES intends to use a finer grid once 3D seismic data have been acquired and incorporated.

Variogram modeling using the petrophysical logs showed ".. .a NE-SW depositional trend, with a vertical resolution of roughly 20 ft. by 20 ft. is likely representative of larger depositional changes (for example from high-stand to low-stand sea level). To capture smaller changes within each depositional cycle, 4 ft layer increments were defined for each zone."

These increments are geologically reasonable. It is understood that the geomodel will be updated and refined once new, more detailed site-specific information are available.

2.3.2.4 Fault stability

There are currently limited data to assess the stability of faults. As noted above, the application indicates that geomechanical information will be collected during the pre-operation phase via core analyses, pilot hole logs, and well tests. The narrative notes that in-situ stress can be assessed integrating the density of the rock above the depth of interest (vertical stress), and minimum and maximum horizontal stresses will be assessed via mini-frac testing and other methods. The application indicates that these new data, along with 3D seismic profiling, will allow characterization of the in-situ stress field, pore pressure, and rock strength. The geomechanical model that these data will support will be used for a more comprehensive analysis of fault stability and sealing capacity.

The application cites a study by Chiaramonte et al. (2008) describing the development and application of a geomechanical model for the Tensleep Formation to support consideration of a CO_2GS project at Teapot Dome. Chiaramonte et al. used the geomechanical model to estimate the pore pressure that would cause fault slippage. The methods used by Chiaramonte et al. are thorough in terms of the geomechanical characterization of the site and include a probabilistic sensitivity analysis. At this point, we assume that CES intends to follow the same approach once they have the necessary data. EPA will evaluate the data, geomechanical model, and conclusions when it has been developed.

2.4 Evaluation of the Computational Model Design

As noted above and in the site characterization report, CES's modeling is based on preliminary data, which will be refined when the injection and deep observation wells are drilled and additional data (e.g., formation data and 3D seismic) are collected. Specific elements of and considerations in our review are described in the sections below.

Routines for Relevant Subsurface Processes

CES used the ECLIPSE 300 (v2018.2) reservoir simulator with the CO2STORE module to perform the AoR delineation. ECLIPSE includes routines for the relevant subsurface processes at the site, including equations of state for CO_2 and other chemical species of interest.

As Attachment B describes, "ECLIPSE 300 is a compositional finite-difference solver that is commonly used to simulate hydrocarbon production and has various other applications including carbon capture and storage modeling. The CO2STORE module accounts for the thermodynamic interactions between three phases: an H2O-rich phase (i.e.,'liquid'), a CO2-rich phase (i.e.,'gas'), and a solid phase, which is limited to several common salt compounds (e.g. NaCl, CaCl2, and CaCO3). Mutual solubilities and physical properties (e.g. density, viscosity, enthalpy, etc.) of the H2O and CO2 phases are calculated to match experimental results through a range of typical storage reservoir conditions, including temperature ranges between 12°C-100°C and pressures up to 60 MPa. Details of this method can be found in Spycher and Pruess (2005)."

Geochemistry was not included in the numerical modeling. The narrative does discuss the geochemical modeling that was done separately; this content was addressed in the site characterization evaluation included in EPA's technical evaluation comments and information request dated August 19, 2020. Coupled geochemistry and multiphase flow would allow exploration of potential effects of mineral dissolution and precipitation on porosity and permeability and the possible long-term effects of mineral trapping on storage capacity. We understand, however, that there can be challenges in simulating changes in petrophysical properties because of factors such as sediment texture and grain morphology.

- Will reactive transport modeling be attempted when additional data are available? If not, please explain how the lack of incorporation of geochemical reactions into the model may (or may not) limit the accuracy of the predictions of plume and pressure front migration.
  - *Geochemical batch reaction modeling based on the preliminary data indicated that there is no significant impact on the rock properties from CO_2-water-rock reactions. The formation rock is composed of a mineral assemblage commonly found in sedimentary rocks whose reaction pathways with CO_2-saturated brine are relatively well understood. After a characterization well is drilled, the site-specific data will be used with the geochemical modeling to update and evaluate the effect of geochemical reactions on petrophysical properties. Application of reactive transport modeling will be considered after the mineralogic, petrographic, and geochemical data have been reviewed and when newly found mineralogic and sedimentary characteristics could potentially lead to significant impacts.*

EPA Evaluation of Response: The response is acceptable.

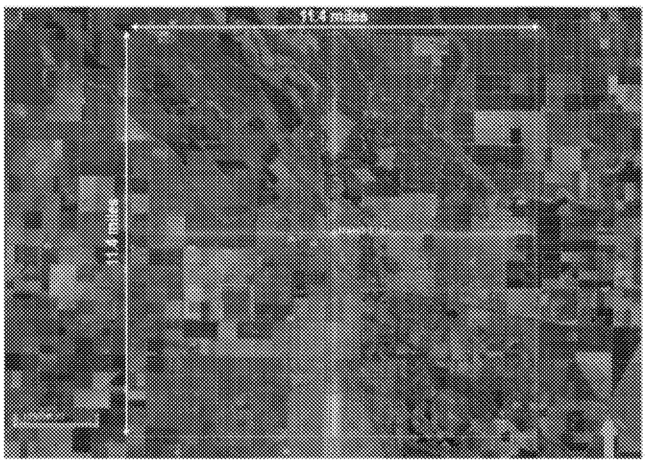
2.4.1 Spatial extent and discretization

The model domain was generated in Petrel. The static grid for the numerical model is 19 miles by 19 miles in the x and y directions. The part of the domain used for dynamic modeling is 11.4 miles by 11.4 miles in the x and y directions, with a tartan pattern of smaller cell sizes closer to the proposed injection well, as shown in Figure 1 of Attachment B, which is reproduced below.

In the Z direction, the domain includes the Garzas Formation (the first permeable sandstone above the Moreno Shale confining zone) down through the basement. The grid comprises "...53 x 53 x 446 cells (totaling 1,252,814) in the x, y, and z direction, respectively, with variable cell sizes. The smallest grid cells around the injector and observation well are 60 ft x 60 ft laterally. Vertical thickness of each cell within the model depends on the vertical proportion of each formation."

This approach to discretization appears to be generally appropriate; it is understood that the horizontalgrid cell size will be reduced as appropriate based on 3D seismic data to be acquired later in the project.

Model Domain and Tartan Grid



2.4.2 Boundary conditions

Section 2.6 of Attachment B states that the upper and lower boundaries were set as noflow boundaries assuming continuous presence of the upper and lower confining zones throughout the project area. At the horizontal boundaries, the cells were set to simulate an infinite-acting boundary by applying a pore volume multiplier of 1×10^6 for each boundary cell.

2.4.3 Time steps

Attachment B, on page 7 describes the time step selection, noting that the software optimizes the time steps to meet converge criteria. "Convergence is achieved once the model reaches the maximum tolerance where small changes of temperature and pressure calculation results occur on successive iterations. New time steps are chosen so that the predicted solution change is less than a specified target."

2.4.4 Model Timeframe

Simulations were run for 20 years of injection into the Second Panoche Sand (which is the upper end of the 12 to 20-year range described in the permit application) and out to 50 years post- injection. Map and cross-sectional views of the simulated plume and pressure front throughout this timeframe were provided in the "AoRs" file submitted in the GSDT.

2.4.5 Initial Conditions and Operational Information

The table below summarizes the initial conditions and operational information used in the computational model submitted via the GSDT. These parameters appear to be appropriate based on the baseline site characterization data and proposed operating conditions described in the permit application. A discussion of specific conditions is presented below the table.

Initial Conditions (and associated reference elevations)	Value
Reference elevation	-9505 ft MSL
Elevation of top of perforated interval	-9400 ft MSL
Composition of injectate	Pure CO_2
Pressure gradient	0.4339 psi/ft (Attachment B, page 14)
Initial Aqueous Pressure	4,211 psi
Initial Temperature	137.5E at -6350 ft MSL 249.7E at -13350 ft MSL
Initial Salinity	25,000 mg/L
Operational Information	**Value**
Mass Rate of Injection	350,000 tons/year
Fracture Gradient	0.65 psi/ft
Maximum Injection Pressure	5677.4 psi
Elevation corresponding to pressure	-9505 ft
Composition of injectate	Pure CO_2
Injection Schedule	Single injection Period (20 years)
Injection Start date	01/01/2021
Number of production/withdrawal wells	N/A
Pressure gradient	0.4339 psi/ft (Attachment B, page 14)

The Second Panoche Sand (the primary injection interval) is located from about 8,90010,000 ft bgs. For most of the operational conditions in the model, a reference elevation of 9,505 ft SSTVD is used. However, it is noted that calculations based on depth (maximum injection pressure and initial aqueous pressure) use 9,705 ft KB (Attachment B, page 19). The reference elevation is located in the middle of the perforated zone which begins at 9,400 ft MSL and extends to 9,620 ft MSL (Attachment B, page 16). Note that, if CES opts to inject into the Fourth Panoche Sand, these values would need to be revised.

The injectate as modeled is composed of pure CO_2. Table 8 of the narrative presents analysis of a sample of the injectate, which is 96.78% CO_2 with impurities, the most notable of which is O_2 (1.15%), which is reactive with redox sensitive minerals present in the formation, and is incorporated into the geochemical model (narrative, page 64). These relatively minor impurities are not a concern for this initial round of multiphase transport modeling. If CES pursues reactive transport modeling in the future, the full composition of the injectate will need to be accurately represented.

Initial aqueous pressure and initial temperature were extrapolated using the reference elevation and DOGGR/CalGEM data from reservoirs near the Mendota site to extrapolate pressure and temperature gradients. Using a pressure gradient of 0.4339 psi/ft, CES estimates pore pressure to be 4,211 psi at the reference elevation. The initial temperature calculation uses two reference points (137.5E at -6,350 ft and 249.7 -F at -13,350 ft), above and below the target perforation zone, to define the initial temperature in between. Based on DOGGR/CalGEM data, the temperature gradient is 0.0146 E/ft with the surface temperature set at 51.8 T.

Initial formation salinity is set at 25,000 mg/L. DOGGR/CalGEM data show that in general, the salinity of Eocene and Cretaceous (Panoche formations are Cretaceous) range between 17,100 and 26,500 mg/L (narrative, page 59). Based on this information, 25,000 mg/L is an acceptable initial condition until more site-specific data are available.

The injection rate of 350,000 tons/year and the 20-year injection period are consistent with the narrative (page 71) and the operating details in Attachment A, which specify a proposed injection rate of 958.9 tons/day (349,998.5 tons/year).

Maximum injection pressure was calculated using the fracture gradient and reference depth, along with a safety margin. The fracture gradient is set at 0.65 psi/ft. Because there is currently no site- specific fracture pressure or fracture gradient in the injection and confining zones, CES used regional data from other sources. A study by Shryock (1968) cites a formation breakdown gradient in the San Joaquin Valley Basin range of 0.63-0.64 psi/ft at depths of 5,000 to 8,000 ft. It is noted that other sources based on studies within California have higher estimates for fracture gradient in the Coalinga district (0.7 and 0.96 psi/ft) (Attachment B pages 16-17). The 0.65 psi/ft. appears to be a reasonable initial estimate for this stage of the application process; the fracture pressure will be revised when a step-rate test has been conducted at this site.

Per the Class VI Rule, the maximum bottom-hole pressure may not exceed 90% of the fracture pressure; this equates to a maximum safe bottom-hole pressure gradient of 0.9 x 0.65 psi/ft = 0.585 psi/ft. Using the reference elevation of -9,505 ft, the fracture pressure is set at 5,677.4 psi.

2.4.6 Relative permeability and capillary pressure curves

In the absence of site-specific lab-based data (i.e., special core analysis or SCAL), the relative permeability/water saturation and capillary pressure/water saturation curves were developed using the Van Genuchten model (Attachment B, Table 2, Figure 7, page 13). Irreducible water saturation (Swir) was assumed to be 0.2 and 0.3 for sand and shale, respectively, and irreducible gas saturation was set at zero. Hysteresis was not considered for either relationship. This is acceptable as an initial step in developing a model.

CES notes that cores from the Mendota INJ_1 well will be subject to SCAL, which will allow the development of site-specific curves. This step will be important, as model predictions are sensitive to the shape of the relative permeability-saturation functions used. Ideally, laboratory core-analysis techniques will be used for experimental measurement of the relative permeability- saturation and capillary pressure- saturation functions at site-specific reservoir conditions, with CO_2 and representative native fluids. If this is not feasible, relative permeability-saturation relationships may be estimated from core analysis using other immiscible fluids (e.g., Doughty et al., 2007). The inclusion or non-inclusion of hysteresis also affects the predicted migration of the CO_2 plume leading edge and predictions of residual trapping.

- Will experimental measurements be done at reservoir conditions, with CO2 and native fluids?
  - *Yes, the laboratory measurement for the CO_2-brine relative permeability function will be performed at reservoir conditions. The salinity of the brine used in the experimental measurement will be prepared to represent the site-specific condition.*

EPA Evaluation of Response: The response is acceptable.

- If it is not possible to obtain reliable laboratory-based data for the relative permeability and capillary pressure curves, will any changes be made to the estimation methods used in the current modeling effort?
    - *The sampling program will incorporate multiple redundant samples, including site-specific cores, to avoid failure in the laboratory testing. However, when the laboratory data are not available, other indirect site-specific information (e.g., irreducible water saturation derived from logs) can be used to update the parameters in the CO_2-brine relative permeability and capillary pressure function.*

EPA Evaluation of Response: The response is acceptable.

- Will hysteresis be considered in model updates?
    - *Yes, the site-specific measurement from special core analysis (SCAL) will provide the information on the hysteresis and will be applied to the dynamic modeling.*

EPA Evaluation of Response: The response is acceptable.

- The curves were developed for two rock types (sand and shale). Given the distribution of porosity/permeability clusters for the different formations (in Figure 30 of the narrative), is it possible a third set of curves will be needed (e.g., for the Fourth Panoche Sand if a backup injection zone is needed)? Will the same curves apply to both of the shale confining zones (First Panoche Shale and Moreno Shale)? (See also the question under "Porosity, permeability, and rock types" regarding the difference in porosity between the Second and Fourth Panoche and whether that might support a third rock type.)
    - *The rock types presented in Figure 30 of the narrative, which are updated in Figure 5, were used for fault seal analysis. The petrophysical property interpolations were completed on a zone-by-zone basis and did not use these facies types in the petrophysical modeling. For example, the unique petrophysical properties (Figure 3) for the Fourth Panoche Sand are accounted for in zone-specific petrophysical modeling. After well log data are acquired, the rock typing will be calculated using a more advanced methodology such as HRA. Likely, this analysis will focus on three to five different rock types, thus enabling characterization of the Second Panoche Sand and other potential injection sands. Different shale classes will be informed by core mineralogy and digital log responses for various shale seals such as the First Panoche Shale (primary) and Moreno Shale (secondary).*

EPA Evaluation of Response: The response is acceptable.

2.4.7 Potential Pathways for Fluid Movement

2.4.7.1 Faults

The block diagram shown in the "Model Domain" file shows strata dipping to the SW, consistent with seismic images in the narrative that are based on 2D seismic data acquired by CES (Figures 16 through 19). Furthermore, the narrative, on page 15 states, "Near the proposed Mendota site, there are two known faults (USGS, 2019) located approximately 5 miles away." See the site characterization evaluation included in EPA's technical evaluation comments and information request dated August 19, 2020 for additional information.

All of these faults appear to be within the 19-mile grid of the model domain. However, the model as currently constructed does not include faults ("AoR Modeling" file), and their effects on fluid flow at the project site remain unexplored at this point due to a lack of data on fault stability and sealing properties. CES anticipates better fault assessment as new data are collected.

- Will any of the faults described in the narrative, especially Fault 13, be incorporated into the geomodel and the numerical model domain once they are better characterized (i.e., with respect to their depth, geometry, and sealing nature)?
    - *Yes, 3D seismic data will enable more accurate interpretation of faulting. The faulting picture is expected to change after interpretation of the more densely sampled 3D seismic data. Faults will be incorporated into a structural framework for dynamic simulation. Fault transmissibility will be calculated using the shale gouge ratio to predict fault permeability.*

EPA Evaluation of Response: The response is acceptable.

2.4.7.2 Wells in the AoR

According to the Corrective Action plan (Attachment B, Section 5), there are 269 wells within a 2.5-mile radius of the Mendota INJ_1 well. This is based on information obtained from the California Natural Resources Agency well completion reports and the DOGGR/CalGEM Databases. Based on information about their depth or (where not available) their use, none are believed to penetrate the confining zone. Information based on the CalGEM online Well Finder database indicates that there are 5 oil and gas wells within 2.5 miles of the injection well; all were dry holes and were plugged. This information was independently verified for this review using searches of the online Well Finder database and well completion reports obtained from the California Natural Resources Agency.

Two wells, Amstar 1 and B.B. Co. 1 penetrate the Moreno Shale into the Panoche Sands. The Amstar 1 and B.B. Co. 1 wells are slated to be plugged, as described in the Corrective Action Plan.

2.4.8 Calculation of critical pressure

The PDF file submitted to the GSDT named "Critical-pressure-calc-01072020" contains the parameters, equation, and the resulting calculated critical pressure for the proposed injection well.

The calculation was done with Method 2 (Pressure front based on displacing fluid initially present in the borehole, which is applicable to hydrostatic case only) described in Section 3.4.1. (Determination of Threshold Pressure Front) of EPA's Class VI Well Area of Review Evaluation and Corrective Action Guidance. The resulting delta P is 3.5 psi. An independent check on the calculations confirms the math is correct using the input values in the file (see the table below).

Z_u	Garzas Reference Datum (ft)	-1415	Bottom of Garzas Formation
	Garzas Reference Datum (m)	-431	
Z_i	Panoche Reference Datum (ft)	-9505	Top, Middle, & Bottom of Panoche Perforation Interval
	Panoche Reference Datum (m)	-2897	
P_u	Pressure in the USDW (Garzas, Psi)	701	
P_i	Pressure in the Panoche (Psi)	4,211	
$P_{u\ water}$	Garzas fresh water density (kg/m3)	1000.0	
$P_{i\ brine}$	Panoche brine density (kg/m3)	1002.0	
G	gravity (m/s2)	9.8066	
$\xi = \frac{\rho_i - \rho_u}{z_u - z_i}$	Density gradient	0.000811	

Without site-specific data, the inputs for the critical pressure calculation are from existing data from a nearby oil and gas field. The brine density of 1002.0 kg/m^3 is consistent with an estimated salinity of 25,000 mg/L. The formation pressure of 4,211 psi at 9,505 ft is based on data from DOGGR/CalGEM.

It is understood that these data and the critical pressure calculation will be updated based on site- specific data collected during drilling of Mendota INJ_1 and OBS_1.

Calculation of the allowable threshold pressure increase using this method is applicable only for hydrostatic conditions. If site-specific fluid pressure and density measurements are not available, the *Area of Review Evaluation and Corrective Action Guidance* notes that it may be acceptable to calculate an initial critical pressure if available information suggests that the formation is likely hydrostatic.

CES has assumed a normal pressure gradient at this time based on initial reservoir pressure data from nearby oil and gas fields (as reported to DOGGR/CalGEM). These data suggest a pressure gradient of 0.4339 psi/ft. The normal pressure gradient will need to be confirmed based on the results of pre-operational testing. Should the results of this testing indicate that the formation is underpressurized, the allowable pressure increase may be greater than that calculated using the equation in the table. If it is overpressured, the allowable pressure increase would be smaller.

2.4.9 Representation of Fluid Properties

Relevant fluid properties for the numerical modeling include: viscosity, density, composition, and fluid compressibility. The table below presents the fluid properties as included in the permit application for the numerical modeling. These may be refined as site-specific data are collected (e.g., salinity and, therefore, density).

Parameter	Units	Evaluation Comments
Viscosity	M/LT	Calculated by modeling program. The CO2 gas viscosity is calculated per the methods described by Vesovic et al. (as cited in Fenghour, 1990) (Attachment B, page 6).
Density	M/L^3	Critical P calculations use 1,000 kg/m^3 for the USDW and 1,002 kg/m3 for the Panoche. 1,002 kg/m3 is consistent with the estimated/anticipated salinity of 25,000 mg/L (see narrative page 63 for estimated salinity). These agree with inputs in the AoR
Composition (salinity)	M/L^3	Narrative page 63 describes the basis for preliminary estimation of 25,000 mg/L salinity for the injection zone. More detailed chemistry was used for the geochemical modeling.
Fluid Compressibility	LT^2/M	Aqueous phase compressibility set to 0, and CO2 set as "compressible." (AoR modeling file).

- Why was the value for aqueous compressibility set to zero, and will this be changed in the next iteration of the model?
  - *The Aqueous Phase Compressibility Value field in the GSDT accepted only numeric values, not text. Therefore, in the Modeled Processes Comments field in the GSDT, CES included the following description of the compressibility of brine: "In Eclipse 300, the compressibility's of brine are based on Ezrokhis formula, which corrects the brine density for dissolved salt and CO2. " Therefore, "0" is used for aqueous phase compressibility value to indicate" Not Applicable."*

EPA Evaluation of Response: Response is acceptable.

2.5 Model Calibration and Sensitivity Analyses

As the permit application narrative and Attachment B note, the preliminary model was developed based on limited site-specific data. There are currently no data available to use for model calibration or history matching. CES describes baseline data collection (e.g., via core sampling in INJ_1 and OBS_1) that will be used for model calibration.
Attachment B (Section 3.2) states that the sensitivity analysis will be performed by varying one variable at a time.

A more complete review of this aspect of the modeling will be done once site-specific data are available from the testing program for calibration and sensitivity analyses.

- Please describe which variables will be manipulated in the sensitivity analysis and how the degree of variation for each variable will be determined.
  - *Uncertain parameters and their degree of uncertainty/variation for the sensitivity analysis will be evaluated and determined after site-specific data are collected. If a statistical variation from the samples cannot be determined, minimum and maximum values will be selected according to the possible ranges/uncertainties based on expert opinion.*

EPA Evaluation of Response: This response suggests CES has not yet considered which variables they are likely to vary for the sensitivity analysis (we assume porosity and permeability at least), nor does it state what statistical measures will help CES in selecting the degree of variation to use in the simulations. The last sentence suggests a possibility that they will have inadequate data for some parameters and may have to use professional judgment to select a reasonable range of values.

While CES's response does not fully address our questions, we do not think further questions at this time will yield useful information. In describing revised modeling results based on the results of pre-operational testing, we expect that CES will clearly present how the sensitivity analyses are done, what data are used to inform the analyses, and the rationales for choices made based on the best available information.

- How will model calibration be performed (e.g., manually or using a computer program)?
    - *Model calibration will be performed with the available testing program (e.g., step rate test and fall-off test) after the injection well is drilled. During the drilling operation, injection rates and corresponding downhole monitoring data (pressure, temperature, CO_2 saturation, and spinner survey) from injection and observation wells will be primarily used for model calibration. Because there is sufficient monitoring data available, a history matching workflow using the MEPO multiple realization optimizer, or the Petrel Uncertainty & Optimization module can be applied.*

EPA Evaluation of Response: The response is acceptable.

2.6 Injection Zone Storage Capacity

CES used a simple volumetric approach to estimate storage capacity, using the number and sizes of cells in the geomodel along with the effective porosity assigned to each cell. Page 71 of the narrative states that, "Within a 2.5-mile radius of the Mendota_INJ_1, the total pore volume of the Second Panoche injection zone is calculated using the 3D geocellular model; for each model cell, the porosity was multiplied by the cell volume. The total pore volume was calculated to be 3.74x10" ft^3."
This is not an unreasonable approach for a general estimate of capacity given that site- specific data collection has not been done yet.

Some assumptions were not specified for this estimate.

- A density value for the CO2 would have been needed to convert the desired number of tons to inject into volume to compare against the pore space. What value was used for the density of the supercritical CO2, and how was it chosen?
    - *The initial storage capacity was reported incorrectly. CO2 density was estimated from pressure and temperature gradients at the midpoints of both the First Panoche Sand and Second Panoche Sand zones. The pressure and geothermal gradients were obtained from nearby oilfield data (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020). Static storage capacity will be reassessed after formation-specific temperature and pressure are acquired. Updated storage capacity estimation results are shown in the table below.*

	Temperature (°F)	*Pressure (psi)*	*Density (kg/cm3)*	*Pore Volume (10*6 m3)*	*P50 Millions Metric Tons*
First Panoche Sand	*177.2*	*3727*	*692.6*	*1466*	*20.3*
Second Panoche Sand	*187.6*	*4035*	*693*	*3000*	*41.58*

EPA Evaluation of Response: The response is acceptable.

The CO_2 storage capacity depends on a combination of factors including multiphase flow processes, formation geometry and types of boundaries (e.g., open or closed boundaries, fault sealing), geologic parameters (e.g., porosity, permeability, compressibility) and their heterogeneity, and subsurface geochemistry. EPA's *Class VI Geologic Site Characterization Guidance* also recommends considering trapping mechanisms. As additional data are collected, the simple volumetric approach can be updated and more refined estimates can be generated (e.g., through dynamic modeling).

- Does CES intend to incorporate additional considerations or use the dynamic modeling being conducted for AoR simulations to generate refined storage capacity estimates?
  - *Refinement of storage capacity estimates will be conducted after structure and petrophysical properties are updated with site-specific data. Storage capacity will be based on CO_2 density, pore volume, and AoR area.*

EPA Evaluation of Response: If we understand correctly, the updated petrophysical properties will be used to refine the AoR based on the results of pre-operational testing, which will, in turn, be used for an updated capacity estimate to be provided after the well is constructed using the same approach as the initial estimate. However, the follow-up questions below should be addressed prior to construction authorization:

Follow-up Questions/Requests for CES:

- Will irreducible water be factored into the pore volume estimate?
  - After petrophysical analysis is conducted using site-specific data, irreducible water saturation will be factored into the future pore volume estimates.

- Is our understanding of the usage of the updated petrophysical properties above correct?
  - Yes.

- Please discuss the strengths and limitations of the approaches considered and clarify how storage estimates will be refined in the future as new data are available
  - *The saline storage equation from the DOE considers 100% brine in the reservoir. It is possible that residual gas is present in the injection formation; however, this is not considered in the saline storage equation. Pressure and temperature data directly from the injection zone will provide a more accurate estimation of storage capacity. Storage estimates will be refined as new data are available from the drilling of a characterization well.*

EPA Evaluation of Response: The response is adequate for the current state of the application.

Follow-up Questions/Requests for CES:

Future versions of the AoR and Corrective Action Plan (i.e., based on the results of pre-operational testing) should clarify/include the following:

- Provide the DOE saline storage equation.
- The narrative states on page 40 that, "…the total pore volume of the Second Panoche injection zone is calculated using the 3D geocellular model; for each model cell, the porosity was multiplied by the cell volume," resulting in a stated total of 3.74x1011 ft3. Is it correct that the DOE saline storage equation is applied to each cell in the geocellular model?
- Please indicate the level of uncertainty in the estimate. Is it an upper bound, lower bound, or middle range estimate? What factors might cause the storage capacity to differ from this estimate?

2.7 Presentation of Model Results

Map and cross-sectional views of the simulated plume and pressure front were provided in the "AoRs" file submitted in the GSDT. The maps show the position of the plume and pressure front after 6 months, 5 years, and 20 years of injection, and 10 years, and 50 years post-injection.
Figure 11 is CES's proposed AoR as delineated by the simulation model.

The differences in the predicted position of the plume and pressure front between the cessation of injection, 10 years post-injection, and 50 years post-injection were fairly minor, suggesting that the plume movement may remain stable after injection ceases. Updated modeling when more data have been acquired will be needed to refine the modeled predictions.

2.8 AoR Reevaluation Schedule

CES described the procedures and timing for AoR reevaluations to be performed during the injection and post-injection phases. At this point in the permit application review, the five-year default reevaluation schedule appears to be appropriate. CES also identified events that would warrant an unscheduled AoR reevaluation, and EPA has the following questions and recommendations.

- Regarding reviewing available monitoring data for comparison to the model predictions, the specific types of data (e.g., the seismic methods to be used) will need to be refined as the injection and post-injection testing and monitoring strategies (in Attachments C and E) are finalized. EPA also recommends the following revisions to these planned reviews:

    - Reviews of available data on the position of the CO2 plume and pressure front should reference analysis of fluids sampled in OBS1.

    - Reviews of ground water chemistry monitoring data should reference data from ACZ1 in addition to the shallow monitoring wells and USDW1.

- *In the updated version of* Attachment *B (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020), the above data reviews will be added.*

EPA Evaluation of Response: The response is acceptable; we will confirm that the plan was updated as described when CES submits their revised AoR and Corrective Action Plan prior to construction authorization.

- EPA recommends including additional triggers for unscheduled AoR reevaluations:
    - If the arrival time of the plume and/or pressure front at OBS_1 and/or when pressure and plume data recorded at OBS1 differs significantly from modeled projections.
    - Initiation of competing Panoche Formation injection projects within the same injection formation within a 1-mile radius of the injection well.
    - Significant land use changes that would affect site access.
  - *The above EPA recommended triggers will be added to the updated version Attachment B (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020).*

EPA Evaluation of Response: The response is acceptable.

- What is the timing for initiating an AoR reevaluation that is triggered based on the events described (e.g., within one month of identifying the existence of the event)?
  - *After a triggering event is identified, investigated, and confirmed, an AoR reevaluation will be completed. The exact timing of an AoR reevaluation will vary depending on the triggering events in section 6.2 of Attachment B (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020); however, a 1- month timeframe is likely. CES will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required.*

EPA Evaluation of Response: The response is acceptable; please note this in the updated plan.

- Please remove pressure from the list of hydrochemical/physical parameters identified immediately above the confining zone, as pressure will not be monitored in ACZ1.
  - *Pressure monitoring with other tools above the confining zone is designed to monitor leakage of brine and/or CO_2 past the Moreno seal. It was described in the page 7 in Attachment C.*

EPA Evaluation of Response: The well is described on page 7; however, pressure monitoring in ACZ1 (which is the only well to be completed immediately above the confining zone) is not described on Table 11 of the Testing and Monitoring Plan.

Follow-up Question/Request for CES:

- Please either clarify where pressure will be monitored in ACZ1 or revise the Testing and Monitoring Plan. This information should be provided prior to construction authorization.

- Yes, pressure will be monitored in ACZ1 and is included in the monitoring plan of ACZ1 as the second bullet point under Section 6 of the Testing and Monitoring Plan. Table 11 in Testing and Monitoring Plan is for pressure-front tracking within the reservoir.

2.9 Post-Injection Site Care Plan

Certain elements of CES's Post-Injection Site Care and Site Closure Plan (Attachment E) are based on the modeling effort and results and are evaluated below.

As required at 40 CFR 146.93(a)(2)(i) and (ii), CES presented the pre- and post-injection pressure differential and provided a map that illustrates the predicted positions of the CO_2 plume and associated pressure front at site closure.

Figure 1 of Attachment E shows the predicted extent of the CO_2 plume and pressure front (1Pc=3.5psi) at site closure. This map and cross-sectional view match the "After 10-year Post- Injection" figure in the "AoRs" file submitted in the GSDT. (See the section on Presentation of Model Results above.)

This figure will need to be updated as needed based on the results of the updated modeling that will be performed as additional site data are collected.

2.9.1 Post-Injection Site Care Time Frame

CES proposed a 10-year alternative post injection site care time frame but did not provide a justification for the appropriateness of the 10-year time frame that addresses the criteria at 40 CFR 146.93(c). CES notes that the Post Injection Site Care Plan will be finalized based on the results of updated modeling performed after pre-operational testing is complete.

As discussed under "Presentation of Model Results," the differences in the predicted position of the plume and pressure front between the cessation of injection, 10 years post-injection, and 50 years postinjection were fairly minor, suggesting that the plume movement may remain stable after injection ceases, which may justify a 10-year post-injection site care timeframe. Future versions of
Attachment E will need to address each of the criteria at 40 CFR 146.93(c) based on the site-specific data collected.

This discussion will be revised as necessary during the review of the pre-operational phase AoR modeling.

2.9.2 Non-Endangerment Demonstration Criteria

In Section 6 of the Post-Injection Site Care and Site Closure Plan, CES described the contents of a non- endangerment demonstration report that would contain: a summary of existing monitoring data; computational modeling history; and evaluations of reservoir pressure, the CO_2 plume, and emergencies or other events. The following recommendations are offered to provide for a set of criteria that are as specific as possible and can be supported by the data CES will collect during injection and post-injection testing and monitoring. It is recognized that several related parts of the project are under development (e.g., testing and monitoring activities, AoR modeling); however, these recommendations are offered to reduce future uncertainty.

- The criteria should specify that the same delineation model that supported the initial AoR delineation will be used in future reevaluations and to make the non- endangerment demonstration to facilitate verification and/or model calibration using actual monitoring and operational data.
    - *The methods used for delineating AoR will be consistent throughout the life of the project including the non-endangerment demonstration and will be specified in the updated version of Attachment B (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020).*

EPA Evaluation of Response: The response is acceptable; we will confirm that the plan was updated as described in the responses in this section when CES submits a revised PISC and Site Closure Plan with the updated permit application prior to approval for construction.

- The criteria should discuss the predicted behavior of the CO2 plume and pressure front, supported by maps and graphs (e.g., of pressure profiles or extent of the plume and pressure front) in the context of the data that will be collected to demonstrate that the plume and pressure front are behaving as predicted at various points in time.
  - *This will be added to the updated version of non-endangerment demonstration criteria in Attachment B (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020).*

EPA Evaluation of Response: The response is acceptable.

- The data that will support the non-endangerment demonstration should be consistent with the final injection and post-injection phase testing and monitoring strategies in Attachments C and E. For example, the geophysical methods selected (i.e., 2D vs. 3D seismic surveys) should be consistent. They should also be specific as to the types/locations of data that will be gathered and compared against the model prediction to facilitate model validation (e.g., the formations for which groundwater quality data will be collected and pressure monitoring locations).
  - *The 2D seismic data mentioned in Attachment C was purchased in 2019 and used for the initial structure mapping. All subsequent seismic acquisition will be 3D. An initial 3D surface seismic survey will be conducted to more accurately characterize the subsurface structure. For subsequent monitoring, a 3D vertical seismic profile (VSP) may be substituted for a 3D surface seismic survey if this is acceptable to the EPA. If this was to be proposed, it would be discussed with the EPA first.*

EPA Evaluation of Response: The response is acceptable; we will confirm that the Testing and Monitoring Plan includes injection-phase 3D seismic surveys when CES submits a revised plan prior to construction authorization. (Responses to RAI 4 indicate this is planned.)

- The criteria should include an evaluation of natural and artificial potential conduits for fluid movement, including the faults described in the geologic narrative.
  - *A clearer picture of the faulting at the site will be established after the 3D seismic data are acquired and interpreted, and the positions of the faults will be registered with the microseismic monitoring program. The location of microseismic events will be compared to the locations of the interpreted faulting from the 3D seismic data. This information will be included in Section 6.6 in Attachment E (Schlumberger, Attachment E: Post-Injection Site Care and Site Closure Plan,2020).*

EPA Evaluation of Response: The response is acceptable.

- The non-endangerment criteria should include evaluations of mobilized fluids and passive seismic data. It appears that the discussion in Section 6.6 addresses these evaluation areas.
- The non-endangerment criteria should include a summary of any emergencies or other

unanticipated events that may occur during the injection and post-injection phases. This may be presented in a table that shows (1) examples of unanticipated events that might occur, and (2) the types of data that might be used to demonstrate that any associated issues have been resolved such that there is no endangerment to USDWs.

- *CES will incorporate the recommendations into future versions of Attachment E (Schlumberger, Attachment E: Post-Injection Site Care and Site Closure Plan, 2020).*

EPA Evaluation of Response: The response is acceptable.

3 Appendix A: Updated Tables and Figures

Table 2: Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
Surface	2026	psi
Downhole	5677	psi
Average Injection Pressure		
Surface	1042	psi
Downhole	4212	psi
Maximum Injection Rate	958.9	tons/day
Average Injection Rate	958.9	tons/day
Maximum Injection Volume and/or Mass	350000	tons/year
Average Injection Volume and/or Mass	350000	tons/year
Annulus Pressure	*5777*	psi
Annulus Pressure/Tubing Differential	100	psi

2. Injection Well Operating Conditions

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE
Maximum Injection Pressure – Surface	2026 psig
Maximum Injection Pressure – Bottomhole	5677 psig
Annulus Pressure	*5777 psig*
Annulus Pressure/Tubing Differential	100 psig
Maximum CO_2 Injection Rate	958.9 tons/day

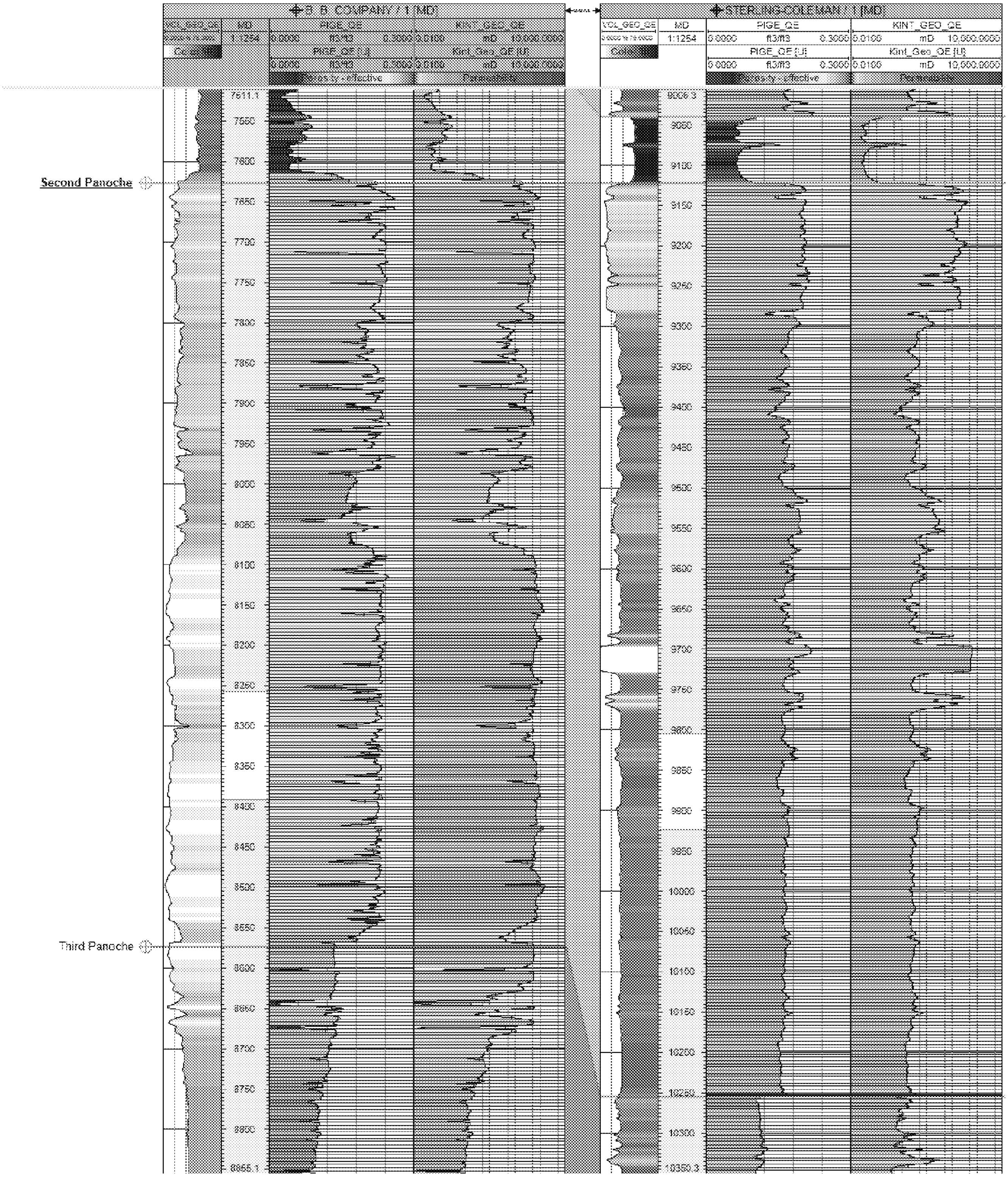


Figure 1: Well log upscaling of the two nearest wells over the Second Panoche Sand (from Petrel 2019).

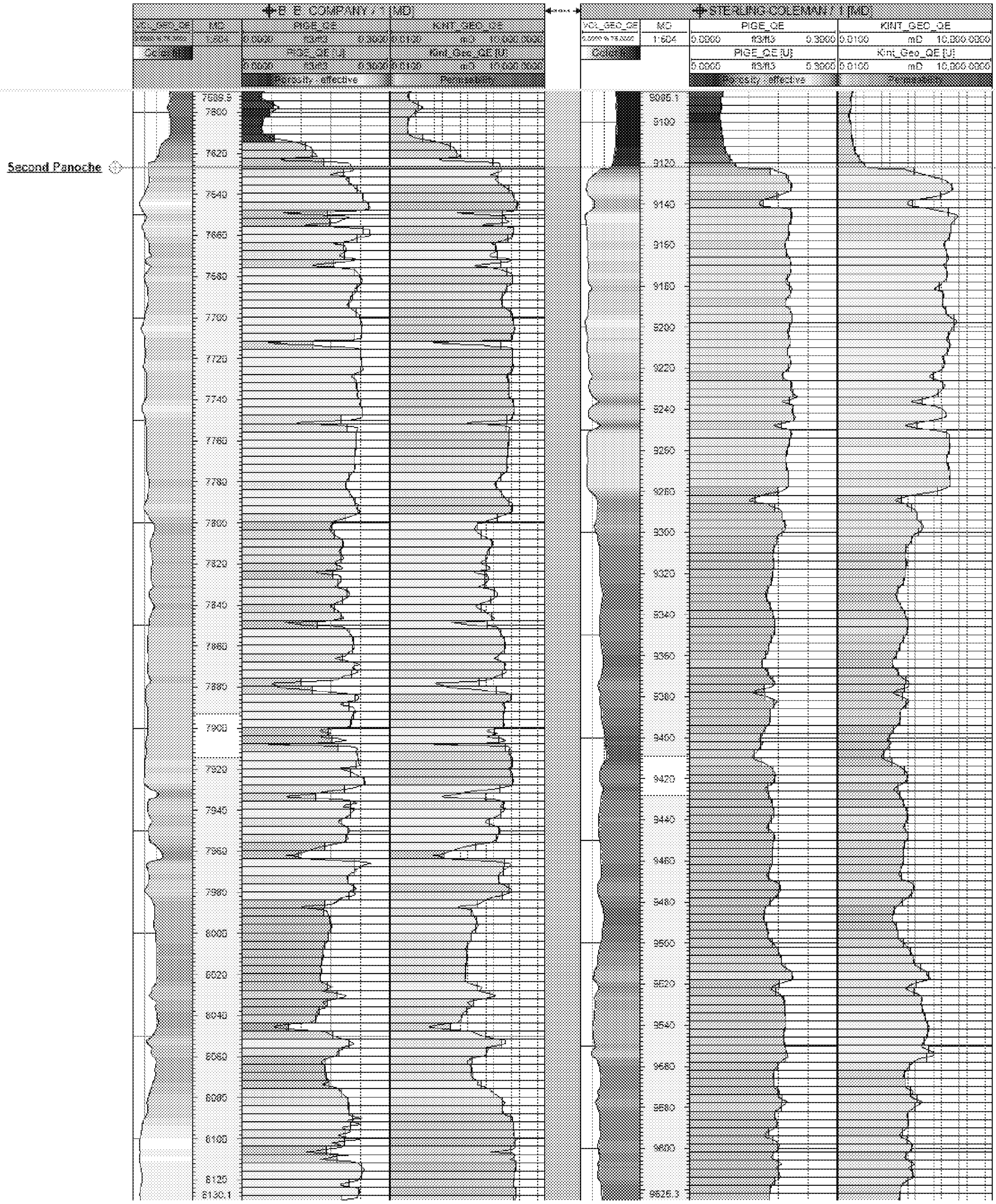


Figure 2: Well log upscaling of the two nearest wells over the upper section of the Second Panoche Sand (from Petrel 2019).

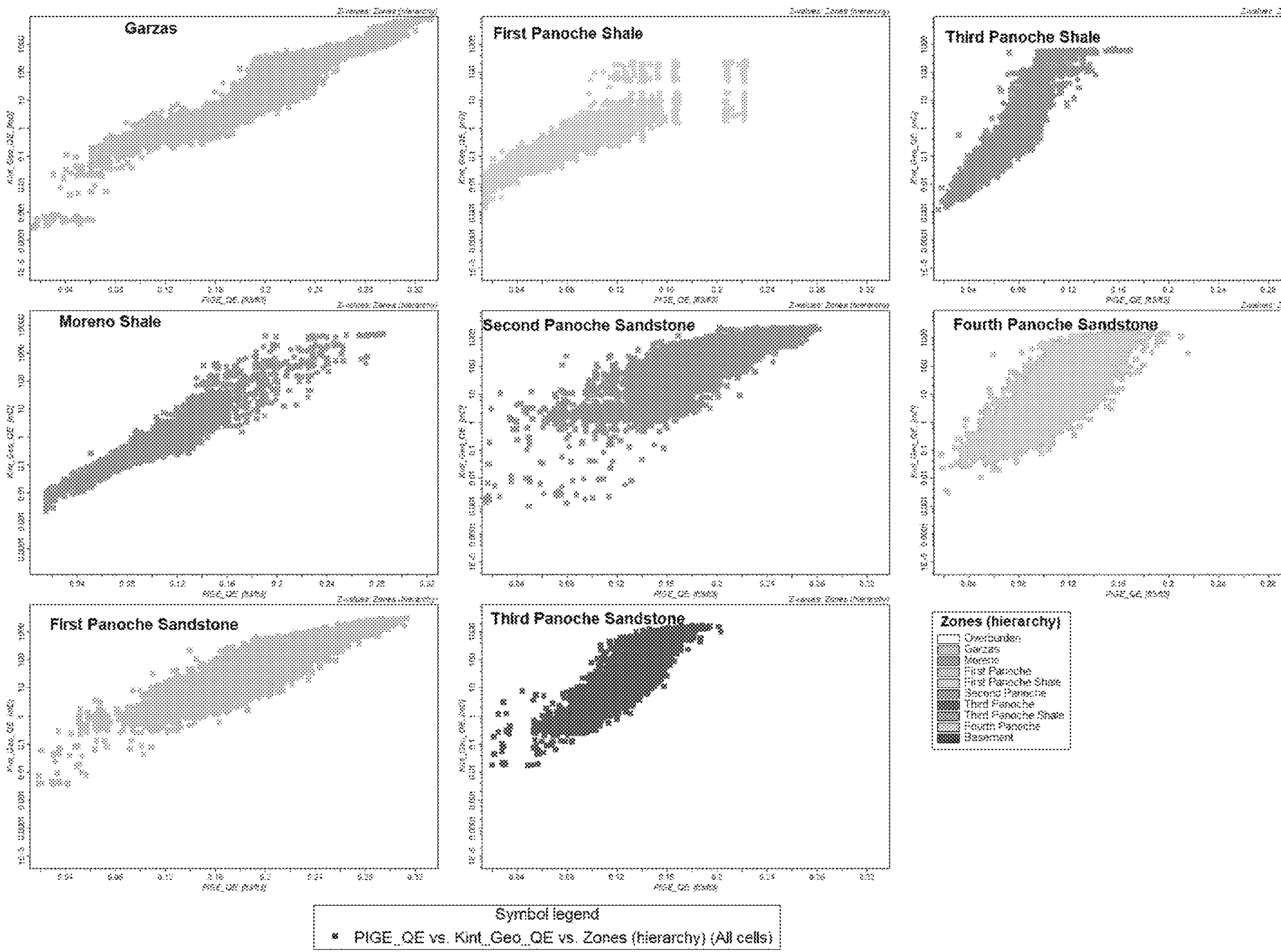


Figure 3: Porosity-permeability crossplot model cells colored by formation (from Petrel 2019).

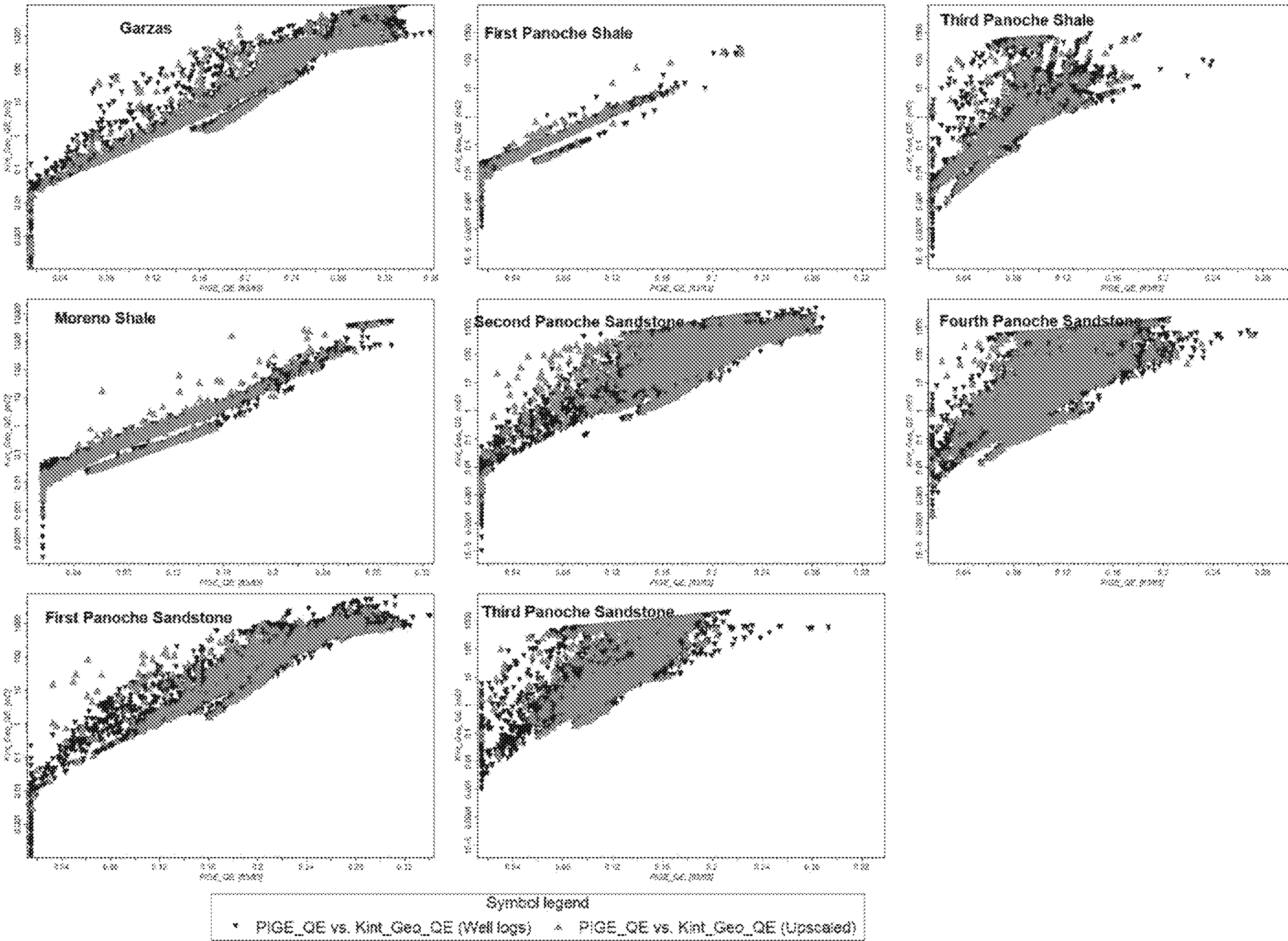


Figure 4: Porosity-permeability crossplots of well logs and upscaled cells (from Petrel 2019).

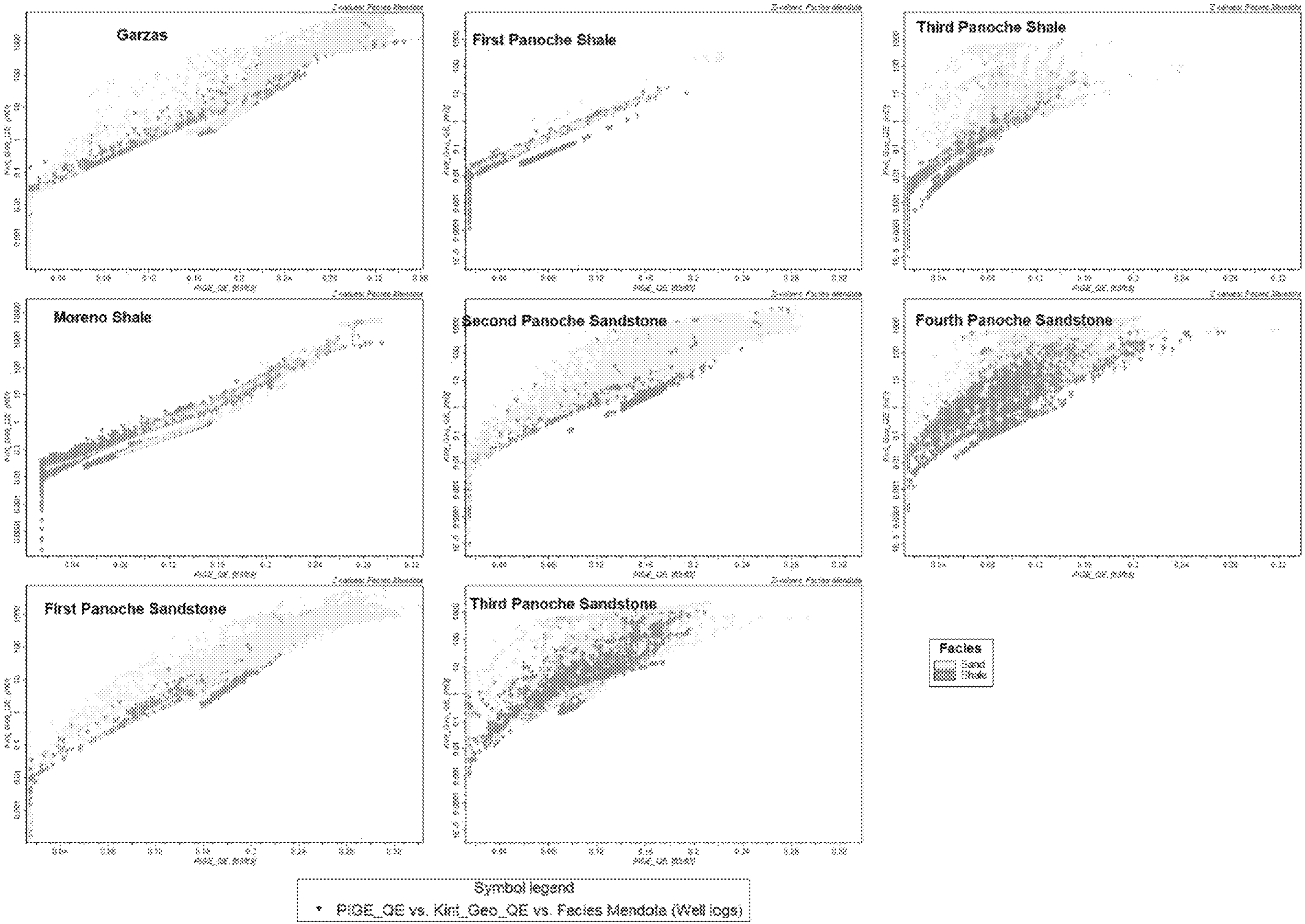


Figure 5: Porosity-permeability crossplots of well logs vs. facies type (sand and shale) (from Petrel 2019).

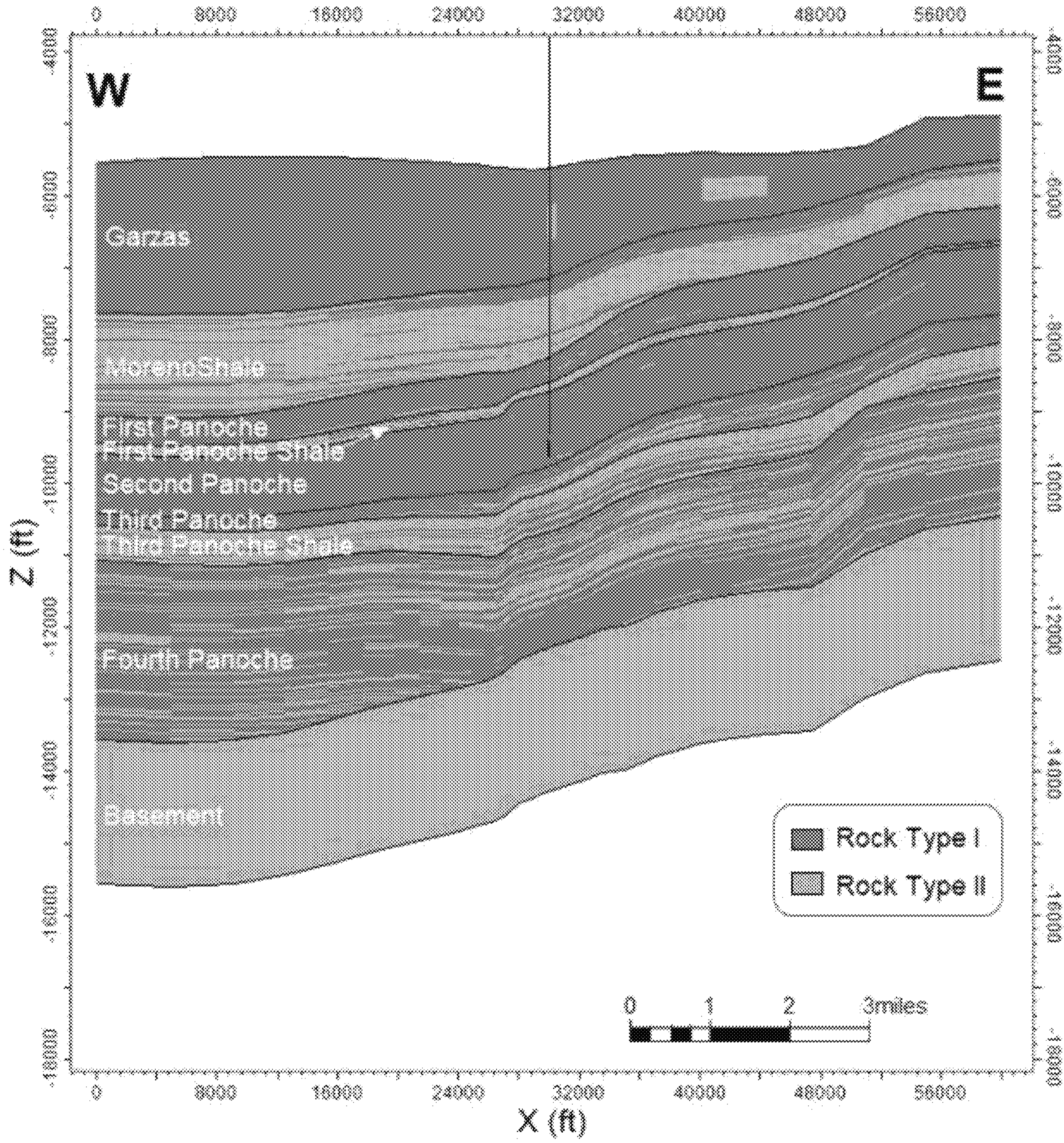


Figure 6. Rock types along the E-W cross section (from Petrel 2019).

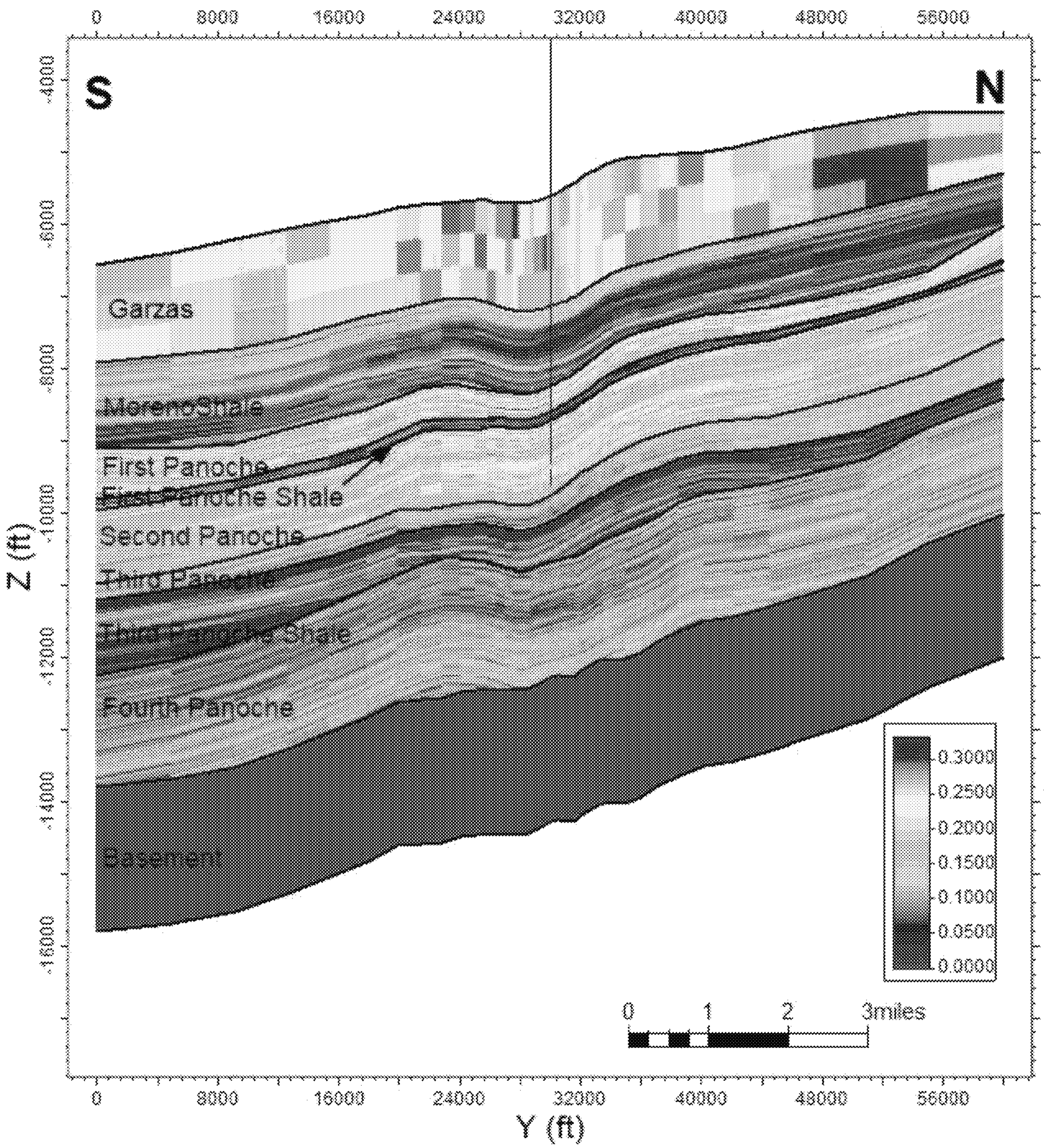


Figure 7. Upscaled porosity profile along the N-S cross-section.

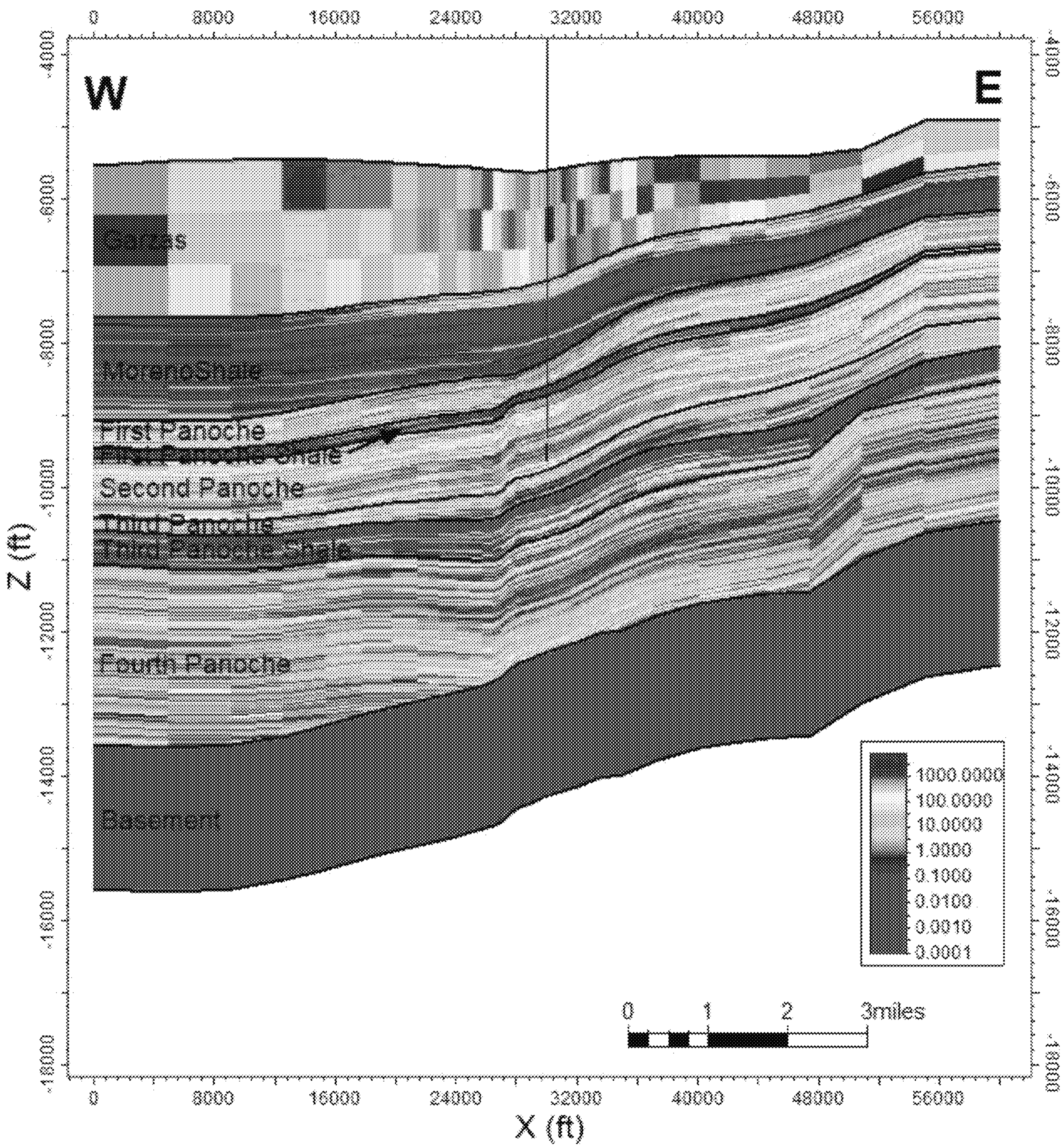


Figure 8. Upscaled permeability profile along the E-W cross-section.

ENCLOSURE 4

Evaluation of Applicant Responses to EPA's Technical Review Comments on the Proposed Well Construction, Plugging, and Corrective Action Activities in the CES-Mendota Class VI Permit Application

EPA reviewed responses provided by Clean Energy Systems (CES) to EPA's questions about the CES-Mendota Class VI UIC Permit. EPA's Technical Review Comments and recommendations (dated October 28, 2020) are in blue text. CES's responses (dated November 2, 2020) are provided in green text. EPA evaluations are in red text. EPA expects that most of these questions can be answered based on available information and requests that they be addressed in the updated permit application that CES plans to submit later in 2021. However, where applicable, EPA notes below that some cannot be fully addressed until the well is constructed and pre-operational testing is performed. No confidential business information is included in this document.

3.1 Injection Well Construction

Section 5 of the permit application narrative and Attachment G describe the proposed injection well construction design. The proposed injection well design is presented in Figure 1 of Attachment G and Figure 51 of the narrative. The figure shows the position of the various casing, tubing and perforations to be implemented in the Mendota_INJ_1 injection well.

The proposed injection well will be a new vertical well, to be drilled with a deviation of less than 5 degrees. The application explains that well logs to provide formation properties and any needed formation sampling will be run from 7,432 feet to 1,800 feet (see additional evaluation under "Pre-Operational Testing of the Injection Well," below). If, based on cement and casing evaluation logs, a competent formation to set casing is found above the Third Panoche Shale, then the 9-5/8 inch hole may not be drilled to 10,412 feet. A 7 inch, 38 lb/ft, T-95 Type 1 casing from 0 to 7,332 feet and then 7 inch 38 lb/ft TN9513Cr casing from 7,332 feet to 10,412 feet will be run into the hole and cemented to surface. After the cased hole logs are run, the well will be perforated and completed with an injection packer and 3-1/2 inch L-80 13Cr tubing string. The perforation interval will be selected based on the log analysis, but is anticipated to be from about 9,600 feet to 9,820 feet.

Well construction will provide 3 casing barriers with generously cemented annuluses covering the USDW from the surface to 1,800 feet. Covering the USDW will be the 16 inch, 10-¾ inch, and 7 inch casings.

A removable 3-½ inch tubing string with a retrievable seal bore packer will be used to facilitate movement and changeout of the tubing string and allow for needed testing. The tubing string will be fitted with nipple profiles to facilitate testing of the tubing, packers, and tubing annulus. Pressure and temperature monitors will be installed downhole and at surface on the various annular ports for the casing wellhead and tubing.

All casings will be cemented to surface. The application states that there are currently no known conditions preventing bringing cement to surface without a stage collar on the surface, intermediate, and long strings.
Coverage of the annulus and cement strength will be evaluated with wireline cement bond log (CBL) and ultrasonic cement evaluation logs.
The conductor casing is expected to be driven but a provision has been allowed to drill a hole and cement the casing if soil conditions do not permit driving the casing to 86 feet.

The surface casing will cover the USDW at a maximum depth of 1,415 feet TVD. Surface casing depth is expected to be 1,800 feet. Type II/V cement meets ASTM Specification C 150. It is a low alkali Portland cement for general use and where high sulfate resistance is required.

The intermediate casing will be set 100 feet into the top of the Moreno Shale confining zone. Cement will be brought back to surface from 7,432 feet TVD. Class G cement is an API grade cement with specifications defined in various API standards, primarily API Spec 10A. Pozzolan will be an additive to reinforce the cement slurry.

The long casing string will be set 100 feet into the Third Panoche Shale but may be set higher if an appropriate formation can be found. Cement will be brought back to surface from 10,412 feet TVD without a need for staging equipment. The CO_2 resistant EverCRETE* will be taken to above the Moreno Shale with a top of 7,332 feet to 7,000 feet. The application describes EverCRETE* as state of the art for storage of CO_2 for GS and enhanced oil recovery projects that can be incorporated into standard primary cementing operations for zonal isolation of new CO_2 injection wells.

Comments on Well Construction Procedures and Materials

The Class VI Rule requires that well component materials be compatible with the planned injectate and formation fluids that may be encountered and can resist corrosion for the duration of the project. The application states that materials suitable for CO_2 environment are clearly specified in API, ANSI/NACE and ASTM standards and that suppliers of components will be required to demonstrate and provide certification that their equipment has been tested and evaluated against these standards and that they are suitable for purpose in the environment defined.

While a preliminary injectate composition is described in the narrative, the application also states that well construction materials will be reviewed following tests of the composition, properties and corrosiveness of the injectate. When CES provides details about the specific materials, EPA will conduct a fuller evaluation. However, based on the impurities anticipated to be in the CO_2 injectate, as listed in Table 8 of the narrative (i.e., H_2O, O_2, H_2, N_2, CO, Ar, NO, NO_2, $H2_s$, and NH_3), CES's proposed approach to construction appears to be acceptable.

The strength of all proposed well materials must be capable of resisting all of the forces encountered. The application states that casing selection has been evaluated against industry standard worst-case loads to determine if selected casing sizes, material thickness and grade are suitable for the environment in terms of pressure and temperature. Where applicable, special loads were created to determine if the casing could handle a load not covered by current standards. Areas evaluated are casing/tubing burst, collapse, axial and compressive strengths in unilateral, bilateral and triaxial (Von Mises) load scenarios.

Tables 10 to 14 in the application narrative provide casing design specifications and details. There are inconsistencies between the text and the casing details in Tables 13 and 14 regarding the casing grade to be used in the surface, intermediate, and long string casings. The text states the grades as L-80 for the intermediate casing and long string casing but T-95 in the two tables. The grades listed in Tables 13 and 14 are also inconsistent for the surface and intermediate casing strings.

- *Please refer Table 4-3 in Appendix A of this document which updates Table 14 below for the correct material types for the surface and intermediate strings.*

Table 13: Mendota INJ 1 casing specifications

Name	*Depth Interval (feet)*	*Outside Diameter (inches)*	*Inside Diameter (inches)*	*Weight (lb/ft)*	*Grade (API)*	*Design Coupling (Short or Long Threaded)*	**Thermal Conductivity @ 77°F (BTU/ft hr, °F)**	*Burst Strength (psi)*	*Collapse Strength (psi)*
Conductor	86	22	21	197.41	B	Welded	26.13	2440	1950
Surface	1800	16	15.01	84	N80	Long	26.13	4330	1480
Intermediate	7432	10.75	9.760	55.5	N80	Long	26.13	6450	4020
Long-string	7332	7	5.920	38	T-95 Type 1	Long	26.13	12830	13430
Long-string	10412	7	5.920	38	TN 95Cr13	Long	14.92	12830	13430

Table 14 : Mendota INJ 1 casing details.

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	86 ft	26 in	1 in	22 in	197.41ppf Grade: B Connection: Welded	16997 lbs
Surface	1800 ft	20 in	0.875in	16 in	84 ppf Grade: Connection: Tenaris ER	151200 lbs
Intermediate String	7432 ft	14.75 in	0.495 in	10.75 in	55.5 ppf Grade: Connection: Tenaris Blue	412476 lbs
Long String	7332 10412	9.625 in 9.625 in	0.590 in 0.590 in	7.0 in 7.0 in	38 ppf Grade: T-95 Type1 Connection: Tenaris Blue 38 ppf Grade:T95-13Cr Connection: Tenaris Blue	422792 lbs

The injection well construction procedures and materials are satisfactory except as discussed and noted below.

Comments on Cementing

The proposed cementing procedures must provide a continuous sheath of cement from the bottom of each casing string to the surface with placement of the surface casing below the depth of the lowermost USDW. The application states that all three casing strings will be cemented from total depth to the surface and will provide three casing barriers with cemented annuluses covering the USDW from surface to 1,800 feet. As noted in the geologic evaluation report, formation sampling will be performed to confirm the depth of the lowermost USDW; however, a surface casing depth of 1,800 feet is likely to be adequate.

CO_2 resistant EverCRETE cement will be placed from the total depth of the wellbore through the Panoche Formation to above the Moreno Shale. The EverCRETE* system should provide zonal isolation during injection, throughout the life of the well, and after plugging. CES states that it has proved to be highly resistant to CO_2 attack in the most extreme laboratory conditions, including environments with wet supercritical CO_2 and CO_2 water saturation in downhole conditions. As with the well construction materials described above, a definitive determination of the proposed cementing plan is pending final analysis of the injectate; however, based on the anticipated impurities in the CO_2 stream, CES's proposed cementing approach appears to be acceptable.

Questions/Requests for CES:

- *Please clarify the casing grade for the surface, intermediate, and long string casings in the text and in Tables 13 and 14.*
- *Please refer to Table 4-3 in Appendix A, which is the updated Table 14.*

EPA Evaluation of Response: Table 4-3 indicates that the grade of the surface and intermediate casing materials is N80, which is consistent with information in Table 13 of the permit application narrative. This response is acceptable. However, the narrative description of the casing specifications is still inconsistent with the casing grade information in Table 4-3 and should be revised when the updated construction plan is submitted.

- *Please provide data from the manufacturer that demonstrates EverCRETE is more protective than Portland Cement under the deep well conditions of CO_2attack. How long will EverCRETE endure under long term CO_2 corrosive conditions, and what data support these conclusions?*
- *Barlet-Gouedard et al. (2006) describe how the EverCrete system is different from and superior to conventional Portland cements (Barlet-Gouedard, V., Rimmele, G., Goffe, B., and Porcherie, O. 2006. Mitigation Strategies for the Risk of CO_2Migration Through Wellbores. SPE-989284- MS. https://doi. org/10.2118/98924-MS).*

EPA Evaluation of Response: This SPE paper compares the performance of Portland cement with a "new CO_2-resistant material," (which is assumed to be EverCRETE). It concludes that the material has good mechanical behavior and remains comparatively inert in the presence of wet CO_2. It does not directly address the longevity of EverCRETE; however, such information may not be available for CO_2 GS applications. No further questions.

- *Are capillary tubes used for installation of either fiber optics or other equipment external to the casing? If so, what is their internal diameter, and how will they be plugged at the end of the well's life?*

- *Cables are used for both fiber optics and gauges, though they are not technically capillary (hydraulic) lines; however, if they were to get compromised, it is possible to have a leak path to surface. This is mitigated with a wellhead outlet. At the end of the well's life, a plug can be put on the end of the cable. Cables will be pulled with tubing at end of life*

EPA Evaluation of Response: Response is acceptable.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *CES will need to demonstrate that the selected well component materials are compatible with formation fluids that may be encountered, as described in the results ofpre-injection formation testing, and that they can resist corrosion for the duration of the project*
- *Comment noted. CES does not expect any changes as per current information on fluids to be encountered. With low chlorides and no H_2S, the fluids should be easily handled by current materials prescribed.*
- *The surface casing depth/cementing specifications may need to be modified based on the results of analyses of sampled formation water during drilling of the injection and monitoring wells to determine the base of the lowermost USDW.*
- *Noted: As new information is collected about the USDW, casing depth/cementing specifications will be adjusted.*
- *Following the pre-construction measurement of the composition, properties, and corrosiveness of* the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.
- *Noted: As plant facilities are designed and adjustments are made to the output CO_2 stream, the well construction materials will be reviewed and corrected for appropriateness to meet design standards.*
- *The final construction schematics should reflect CES's decision to inject into the Second Panoche (the primary injection target) or the Fourth Panoche (the alternate injection zone).*
- *Injection into the Fourth Panoche is unlikely and not currently being planned for. If the Fourth Panoche becomes a target, the final construction schematics will be updated and provided after a site-specific data are collected.*

EPA Evaluation of Responses: The above responses are acceptable at this point in the project. EPA will review updated construction procedures following pre-operational testing.

Additional Question for CES:

CalGEM reports that there has been subsidence in the area of the Mendota site (e.g., in the Gill Ranch Field, subsidence is occurring at a rate of four inches per year). This has resulted in casing collapse and the reemergence of abandoned wells. There is concern that a similar problem could arise at the Mendota site. The Field Rules for the Gill Ranch Field (and others) require relieving stress on the surface casing (e.g., via wellhead design that allows differential movement between the casings). Because Class VI wells have cementing of the surface casing to the surface, flexibility may be needed to address this potential concern.

Has CES considered how it might modify the well design to mitigate shallow compression while still complying with the requirement to cement to the surface?

- CES was not aware of the extent of subsidence in the area at the time of our initial submittal. CES will gather site-specific information to assess the extent of subsidence to determine the significance of compaction to the wellbore. Based on this information, CES will provide options for mitigating the effect of subsidence. Information will be gathered in the coming weeks. A meeting will be requested with EPA – and CalGEM if advisble – to review the options. Review of CalGEM's Field Rules shoe they appear to deviate from EPA's Class VI injection well construction regulation.

3.2 Safety Valves and Shut-Off Devices

The wellhead will be equipped with safety valves and shut-off devices at the injection system and annulus of the well. Automatic shutdown devices would be activated under certain conditions, including when wellhead pressure exceeds the specified shutdown pressure and/or the annulus pressure indicates a loss of external or internal well containment.

The Emergency and Remedial Response Plan, described in Attachment F and Section 4.0 of the application, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. Attachment A describes the shutdown procedures.

Questions/Requests for CES:

- *Please provide additional information about the types of safety valves and shut-off devices that CES proposes to use; in particular, please describe how they will be linked to the continuous injection and annulus monitoring system.*
- *There are currently two options for safety valves that are being evaluated. The first is a subsurface safety valve. This valve is typically mechanical (hydraulic and electrical options available) in operation as it allows fluid to flow during injection phase but will close during cessation offluid flow not allowing downhole fluids or pressures to come to surface. The subsurface safety valve will potentially create excessive downtime as it is in the flow stream and will need to be maintained periodically to maintain functionality. The subsurface safety valve will impede wireline operations because it must be removed before wireline operations can be done. Another option currently thought to be better is to provide pneumatically driven hydraulically actuated gate valves in line with the injection stream in the wellhead. These units can be connected to control systems to drive the opening and closing of the valves based on feeds from downhole signals with respect to temperature and pressure. It is at the surface, so maintenance and replacement are easier and there are more options*

for corrosion-resistant inlays. It will not interfere with any downhole operations such as wireline logging. Examples of the valves and operation equipment can be provided upon request.

EPA Evaluation of Response: The Class VI Rule allows the use of automatic surface shut-off systems (with down-hole shut-off systems at the Director's discretion). This response is acceptable;
EPA expects that CES will provide well schematics and final well construction plans that include the selected devices and will review these when they are submitted.

- Full well and completion schematics will be provided when a finalized design is completed along with discussion of the design.

- *Please revise the injection well schematics to show the surface and downhole pressure and temperature gauges that are referenced in the Testing and Monitoring Plan.*

- *Injection and monitoring wells schematics have been modified and updated with gauge references. Please refer to Appendix B in this document.*

EPA Evaluation of Response: The schematic on page 46 of the response shows the locations of temperature and pressure gauges within the Panoche Formation (at 9,290 and 9,437 feet); this is consistent with information on Table 11 of the Testing and Monitoring Plan. This response is acceptable.

3.3 Pre-Operational Testing of the Injection Well

The proposed pre-operational formation and well testing program required at 40 CFR 146.82(a)(8) and 146.87 is described at Section 6 of in the permit application narrative and in Attachment G. Attachment G describes tests and logs to be performed: at the surface, in the surface section of wellbore, the intermediate section of wellbore, and the total depth section of wellbore, along with tests to be performed during and after casing installation (i.e., cement evaluation and mechanical integrity, formation CO_2 saturation testing, and formation testing). The proposed testing and logging program is considered comprehensive and acceptable, except as noted below.

Questions/Requests for CES:

- *Please add caliper logs to the logging program before surface, intermediate, and long string casing are installed, in accordance with 40 CFR 146.87.*
- *A caliper log was added to the logging programs for all runs.*
- *Please add temperature logging after each casing string is set and cemented in accordance with 40 CFR 146.87.*
- *Temperature logs were added to the cement evaluation program. Multifinger caliper was also added for the mechanical inspection for all casing runs.*

EPA Evaluation of Responses: The updated testing and logging procedures were not included in the response. However, EPA finds this response to be acceptable and will confirm the inclusion of caliper and temperature logs in the updated testing and logging procedures when they are submitted with the revised permit application.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *As described in other reports (e.g., the AoR modeling evaluation and the testing and monitoring evaluation reports), the proposed formation testing program will provide information to support*

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the setting of operating conditions of the permit, provide inputs for modeling to delineate the final AoR, and establish a baseline for parameters that will be measured during injection and post injection phases. As needed, these considerations may be revised as the reviews proceed to ensure that the pre-operational testing and logging program will collect the information needed to verify the well is properly constructed; gather information on subsurface formations and fluid geochemistry; and address all identified uncertainties.

- As more information is gathered, models, programs, and procedures will continue to be updated and reviewed to make sure all identified uncertainties are addressed.

EPA Evaluation of Response: This response is acceptable.

3.3.1 Pressure Falloff Testing (PFOT)

General Comments

The proposed falloff test procedures presented in Attachment G are duplicated in Attachment C (the Testing and Monitoring Plan), but with minor differences between the two attachments. The differences were noted in step 18 of the Falloff Test Report Requirements and in a missing step 2 in the Evaluation of the Test Results in Attachment C that is present in Attachment G. Also, the steps in Attachment C should

be re-numbered for consistency with Attachment G. In addition, steps 3, 4, and 5 in the Pretest Planning section of Attachment C are inconsistent with steps 3 and 4 in Attachment G and the reference to an appendix concerning pressure gauges is missing in Attachment C. The referenced appendix is included in the Region 9 PFOT Guidelines document.

Questions/Requests for CES:

- *Please address the discrepancies between Attachments C and G discussed above and provide a complete and correct copy of the proposed pressure fall-off test procedures and a copy of the referenced Appendix.*
- *Appendix C in this document resolves any differences and gives the updated falloff test procedures according to the comments and suggestions.*
- *Please also include this in the Testing and Monitoring Plan.*
- *Please refer to Appendix in this document for the updated falloff test procedures.*

EPA Evaluation of Responses: The requested changes have been made and, if the same procedures are included in the updated Attachments C and G to ensure consistency, then these responses are acceptable.

- The updated falloff test procedures will be included in Attachments C and G.

The proposed PFOT procedures in Section 8 of Attachments C and G are nearly identical to the Region 9 PFOT Guidelines document, except as noted below:

3.3.2 Timing and of Fall-off Testing and Report Submission

The initial PFOT should be performed upon well completion, but before injection operations begin and annually thereafter, as described in 40 CFR 143.87(e)(1) and the PFOT Guidelines. See additional discussion of the PFOT timing in the testing and monitoring evaluation report.

3.3.3 Fall-off Test Report Requirements

Questions/Requests for CES:

Please add "elapsed time " to the end of the first bullet of Step 18 in Attachment C.

- *Comment noted. Please see Appendix in this document for the updated falloff test procedures.*

EPA Evaluation of Response: The requested change was made; this response is acceptable.

Planning

The ninth bullet is not included in the Region 9 PFOT Guidelines. The testing options described would be subject to EPA approval.

Questions/Requests for CES:

- *Please add that the testing options for use of other pressure transient tests described in the ninth bullet under "Planning" are subject to EPA approval.*
- *Comment noted. The following statement has been added at the end of the ninth bullet (refer to Appendix in this document): "However, other pressure transient tests will be subject to EPA approval prior to the application."*

EPA Evaluation of Response: This response is acceptable.

3.3.4 Pretest Planning

Step 3: Bottomhole pressure measurements are not only superior to surface pressure measurements but are required in all pressure transient tests unless measurement of only surface pressures is approved in advance by EPA. The second sentence is also not applicable to PFOTs unless approved by EPA.

Step 4: This language was added by CES and is acceptable.

Step 5: This is identical to Step 4 in the Region 9 PFOT Guidelines except for omission of the reference to the Appendix in the Guidelines. This step is included in Attachment C, but not in Attachment G; as noted above, EPA requests that the two attachments be consistent.

Questions/Requests for CES:

- Please revise Step 3 under "Pretest Planning" to require bottomhole pressure in addition to surface pressure gauges for conducting PFOTs performed without advance EPA approval for use of only surface pressure gauges.
- Comment noted. Step 3 has been replaced by "Bottomhole pressure measurements are required." Please refer to Appendix in this document for the updated test procedures.

EPA Evaluation of Response: The requested change was made. This response is acceptable.

3.3.5 Conducting the Fall-off Test

Steps 6 through 11 are not included in the Region 9 PFOT Guidelines and were added by CES. They are acceptable with the following exception in Step 9: the maximum injection pressure should not exceed the maximum allowable surface injection pressure specified in the permit, which will be limited based on the formation fracture pressure and a safety factor.

Questions/Requests for CES:

- *Please revise Step 9 under "Conducting the Fall-off Test" to state that the injection pressure will not exceed the maximum allowable surface injection pressure specified in the permit.*
- Comment noted. In Step 9, "but not exceeding the daily injection volume limit of the UIC Permit" was replaced by "but the injection pressure will not exceed the maximum allowable surface injection pressure specified in the permit." See Appendix C in this document.

EPA Evaluation of Response: The requested change was made. This response is acceptable.

3.3.6 Evaluation of Test Results

Step 2 in Attachment G is missing in the PFOT procedures in Attachment C but is not included in the Region 9 PFOT Guidelines. It is an acceptable addition to the procedure, but the Attachment C and G PFOT procedures should be consistent.

Step 3 in Attachment C (Step 4 in Attachment G), fourth bullet in the Attachment C version of the FOT procedure omits the phrase "and skin pressure drop" that is included in the PFOT procedure in Attachment G.

Step 5 in Attachment C (Step 6 in Attachment G) is not included in the PFOT Guidelines but is an acceptable addition to the PFOT procedure.

The language added by CES that follows Step 5 in Attachment C (Step 6 in Attachment G) is acceptable, but the second paragraph referring to "unusual petition approval conditions" is not applicable to Class VI wells. Likewise, the discussion of comparisons of PFOT results to no-migration petition data is not applicable to Class VI permits. However, this information may be relevant to AoR reevaluations.

Questions/Requests for CES:

- *Please add Step 2 to the FOT procedure in Attachment C.*
- *Please refer to Appendix in this document for the updated falloff testing procedures.*
- *Please add the language referring to skin pressure to the FOT procedure in Attachment C for consistency with the language in Step 4 in Attachment G.*
- *Please refer to Appendix C in this document for the updated falloff testing procedures.*
- *Consider revising the discussion in the second paragraph to discuss how unanticipated FOT* results might inform AoR reevaluations.

- Comment noted. The second paragraph after Step 6 and the discussion of comparisons of PFOT results to no-migration petition data have been removed. Please refer to Appendix in this document for the updated falloff testing procedures.

EPA Evaluation of Responses: The requested changes were made and the above responses are acceptable.

Note that there are a few references to a "petition" in the FOT procedures. These do not affect the appropriateness of the procedures; however, EPA recommends revising the text for clarity when the updated permit application is submitted.

Follow-up Question/Request for CES:

- Please remove all references to a "petition" in the FOT procedures for clarity when the updated permit application is submitted.

- Comment noted. All references to a "petition" will be removed in the FOT procedures when the updated permit application is submitted.

3.4 Monitoring Well Construction

EPA recommends in Class VI guidance that monitoring well construction be reviewed in a manner that is similar to the injection well review (especially for the deep ground water monitoring wells).

CES describes seven proposed monitoring wells in the Testing and Monitoring Plan and indicates that the location and design will be finalized in a later phase of the project. EPA requests that CES provide construction procedures and specifications for each well (particularly ACZ_1 and OBS_1) for EPA to review in the context of updated geologic information.

Note that EPA understands that the California Regional Water Quality Control Board will need to approve the construction of any new monitoring wells. While this will not be a UIC permit condition, it is relevant to CES's planning of its monitoring well network and is being shared for informational purposes.

Questions/Requests for CES:

- *Please propose construction procedures and specifications for the proposed monitoring wells. While EPA understands that final locations and depths of the monitoring wells are pending, any available information about the casing, cement, and devices that will be used to sample fluids and measure temperature, pressure, etc., that are described in the Testing and Monitoring Plan is requested.*

Detailed well schematics for the monitoring wells and tables along with plugging diagrams have been provided in Appendix B in this document.

EPA Evaluation of Response: Construction schematics and plugging diagrams/procedures for each type of monitoring well described in the Testing and Monitoring Plan were provided. However, a discussion of proposed monitoring well construction procedures (similar to the discussion of injection well construction procedures in the permit application) should also be provided.

A schematic for the USDW1 monitoring well (on page 48) shows that the well will be cemented from the surface through the base of the USDWs using Class G cement, with a packer set at 1,360 feet (which is above the USDW base at 1,415 feet, per the permit application). A plugging schematic for this well is provided on page 51, which shows cementing from the surface to 1,500 feet.

A schematic for the planned shallow groundwater wells is on page 53; the depth shown (150 feet) is consistent with the planned depth range of 50 to 500 feet in the Testing and Monitoring Plan. It is to be constructed with PVC casing and cemented to its total depth. A schematic for plugging this type of well is on page 54 and shows a cement plug through the entire depth.

A schematic for OBS1 (the injection zone monitoring well) is on page 56. This well is to be completed in the Panoche at a depth similar to the injection well and constructed with surface casing cemented down to 1,800 feet, through the USDW base at 1,415 feet and with CO_2-resistant cement placed in the full length of the long string casing annulus. It is to be equipped with temperature, acoustic, and pressure gauges at the depths of the USDW, above the confining zone, and in the Panoche (which is consistent with the Testing and Monitoring Plan). A plugging schematic for this well is on page 59.

A schematic for ACZ1 (the above confining zone monitoring well) is on page 61. This well is completed at a depth of 7,332 feet (above the Moreno confining zone). It is to be equipped with temperature, acoustic, and pressure gauges at the depths of the USDW and above the confining zone (consistent with the Testing and Monitoring Plan). It has surface casing cemented down to 1,800 feet, below the USDW base at 1,415 feet. A plugging schematic for this well is on page 64.

The information provided in the schematic diagrams is generally consistent with other information in the permit application, including the Testing and Monitoring Plan and information about the depth of the injection and confining zones and USDW. Based on currently available information, this response is acceptable.

EPA will review updated schematics and plugging plans in the context of the results of pre-operational formation testing.

Follow-up Question/Request for CES:

- Please include a discussion of proposed monitoring well construction procedures (i.e., similar to the discussion of injection well construction procedures), in the updated permit application.
- The well construction details, diagrams, and schematics will be updated after pre-operational testing is complete and will be provided in the updated permit application, unless required prior to permit to construct.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The monitoring well construction details and locations will need to be reviewed and modified as necessary based on updated geologic information collected during drilling of the injection well and planned pre-operational seismic surveys.*
- Comment noted. Seismic surveys and initial drilling related to subsurface geologic information will be integrated into the geologic models, which will, in turn, be used to optimize monitoring well location and construction decisions. CES will take every opportunity to maximize the efficacy of subsurface model generation and management to optimize field-based drilling and monitoring activity.

EPA Evaluation of Response: This response is acceptable.

3.5 Injection Well Plugging Plan

The CES injection well plugging plan in Attachment D of the application describes planned tests or measures to determine bottom-hole reservoir pressure and planned internal and external mechanical integrity tests. The MITs are listed in Table 1, and include an acoustic survey and temperature log, as required by 40 CFR 146.92. It also provides information on plugs (with materials and methods noted in Table 2), and a narrative description of plugging procedures. The Post Plug and Abandonment Well Diagram is provided in Figure 6.4.

Table 2 of Attachment D (reproduced below) presents the plugging details.

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	5.92	5.92	5.92	5.92
Depth to bottom of tubing or drill pipe (ft)	9637	7782	1950	100
Sacks of cement to be used (each plug)	145	51	51	20
Slurry volume to be pumped (bbl)	30	11	11	4
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8837	7382	1650	0
Bottom of plug (ft)	9637	7532	1950	100
Type of cement or other material	CO2 Resistant	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced	Balanced	Balanced	Balanced

The bottom-most plug (the only one that is anticipated to come into contact with the CO_2 injectate after injection operations cease) is to be composed of CO_2-resistant cement, and the remaining plugs will be Class G cement. It is not clear why CES is not proposing to use the same EverCRETE product that is proposed in well construction to plug the injection well. If, based on their responses to EPA's questions about EverCRETE, this system is approved, it may be appropriate to use the same product when plugging the injection well.

There are many CO_2-resistant cement formulations. The EverCRETE cement was chosen specifically for the injection casing due to the thin annulus between the open hole and the outer diameter of the casing. There are, however, other suitable options for cementing the casing. The self-healing properties of the EverCRETE system enable the cement to endure during the stress of the injection process during the life of the well. Cement plugs are not subject to these types of stresses and as such do not require such a high-grade cement formulation.

EPA Evaluation of Response: This response is acceptable.

The plugging procedures state that the test pressure should be maintained +/- 10% for 30 minutes in order to pass the test (page 8). The well test pressure during the plugging procedure should not change more than 5 percent in 30 minutes.

- *The plugging procedures will be updated to change "the test pressure should be maintained ± 10% for 30 minutes in order to pass the test (page 8). " to "The well test pressure during the plugging procedure should not change more than ±5% in 30 minutes. "*

EPA Evaluation of Response: This response is acceptable. EPA will confirm the revision when the updated well plugging plan is submitted.

The Injection Well Plugging Plan is subject to revisions to reflect the actual depths of the Moreno and Panoche Formations, selection of the injection zone, and determination of the base of USDWs and final well construction details, based on geophysical logs and interpretation of site geology after the injection well is drilled. Estimated depths of the Moreno and Panoche Formations, injection zone, USDW base, and significant water and hydrocarbon bearing zones encountered should be included in the well plugging schematic.

The cement plug at the base of the intermediate casing is misplaced on the plugging diagram and in Table
It should be placed at 7,582 to 7,382 feet instead of 7,782 to 7,582 feet. The surface plug appears to be placed from +/- 10 feet to the surface but is described as from 100 to 0 feet in the plugging diagram and in Table 2.

According to Figure 6.4, the perforations are 9,337 - 9,537 ft and the bridge plug is proposed to be set at 9,637 ft. This would mean that the bridge plug would be set below the injection perforations, followed by balancing a Class G cement plug across those perforations. EPA recommends the following changes to provide a solid block of CO_2- resistant cement covering the injection perforations and have the benefit of a cement retainer on top of the block with another plug on top of that:

1. Set bridge plug at 9,637'.
2. Set cement retainer at 9,237'.
3. Pump CO_2-resistant cement through cement retainer under pressure (to squeeze some cement into the perforations). Use enough cement to fill the ~400' of 7" casing between the bridge plug and the cement retainer.
4. Sting out of cement retainer and balance 100' - 200' of CO_2 resistant cement atop the cement retainer.

- *Due to the need to have cement 100 ft below perforations per California regulations, it is preferable not to use the retainer to squeeze. To ensure cement is below the perforations, extra operations will be required (i.e., bailer) to fill the gap between the bottom of the perforations and the bridge plug. Using the configuration prescribed above will not allow mud below perforations to be displaced. In addition, there needs to be 500ft of cement above the top of the perforations, as per California requirements. It is likely that two batches of400-ft cement plugs will be needed. The plug procedure will be modified to accommodate both requirements.*
    1. *Set bridge plug at 9,637ft.*
    2. *Pump CO_2-resistant cement to 9237ft.*
    3. *Circulate and two stands above 9237ft.*
    4. *Shut in well and pressure well to 500 psi for 30 minutes to squeeze cement into perforations. This is typically called a hesitation squeeze.*

    Move pipe to top of cement (9237 ft) and commence cement operations with CO_2- resistant cement to achieve cement to 8837 ft depth.

EPA Evaluation of Response. The changes are acceptable as described, except for step 3 above, which is incomplete.

Follow-up Question/Request for CES:

- The description of step 3 ("Circulate and two stands above 9237 ft") is incomplete. Please complete and clarify the description of step 3 in the updated plan.

    3. Pull back two stands above 9237 ft to perform a squeeze operation.

    The revision will be included in the updated plan.

Questions/Requests for CES:

- *Please revise the plugging procedure to state that the test pressures should be maintained at +/-5 % for 30 minutes.*
- *The plugging procedures have been updated accordingly.*

EPA Evaluation of Response: The requested change was made. This response is acceptable.

- *Please add the estimated depths of the Moreno and Panoche Formations, the selected injection zone, the base of the lowest USDW, and significant water and hydrocarbon saturated zones encountered in the wellbore to the well plugging schematic.*

- *Comment noted. CES does not anticipate entering zones of significant water or hydrocarbon saturation at the planned well plug sites. Figure 5-1 of Appendix B illustrates the Moreno and Panoche formations as well as the primary injection zone relative to the well plugging schematic.*

EPA Evaluation of Response: The requested change was made. This response is acceptable.

- *Please correct or clarify the depths of the cement plugs at the intermediate casing shoe and the base of the conductor pipe to the surface in the plugging diagram and in Table 2.*
- *The depth of the cement plugs has been corrected. The diagram was changed for the conductor to reflect the cement plug covering the 22-in. shoe and to surface.*

EPA Evaluation of Response: The plugging diagram on page 47 has been revised to clarify the depths of the cement plugs at the intermediate casing shoe and the base of the conductor pipe in Figure 5-2. However, no plug is provided at the base of USDWs at 1,415 feet.

Follow-up Question/Request for CES:

- Please add a cement plug at 1,519 to 1,315 feet or extend the plug at the surface casing shoe to 1,315 feet to cover the base of the USDW in the updated plan.

- Please refer to updated schematics below.

- *Please revise the depth and procedures associated with the bridge plug at the bottom of the well* as described above.
- *The depth and procedures associated with the bridge plug has been updated.*

EPA Evaluation of Response: The requested change was made. This response is acceptable.

- *Please explain why CES plans to use different cement to plug the well than the one proposed for use in construction.*

- There are many CO_2-resistant cement formulations. The EverCRETE cement was chosen specifically for the injection casing due to the thin annulus between the open hole and the outer diameter of the casing. The healing properties of the EverCRETE system enable the cement will endure during the stress of the injection process during the life of the well. Cement plugs are not subject to these types of stresses and as such do not require such a high-grade cement formulation. For those plugs that are not in contact with CO_2 then conventional Class G cement is considered appropriate.

EPA Evaluation of Response: This response is acceptable.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The Injection Well Plugging Plan and well schematic will need to be revised to represent actual depths of the Moreno and Panoche Formations, the selected injection zone, and the base of the lowest USDW based on geophysical logs and modified interpretation of site geology after the injection well is drilled and completed.*
- *Comment noted. Well schematics will be revised once the well is drilled and formation tops accurately identified.*

- *The final well plugging schematics will need to reflect CES's decision to inject into the Second Panoche (the primary injection target) or the Fourth Panoche (the alternate injection zone) and reflect the final well construction.*
- *Comment noted. The Second and First Panoche are, respectively, the primary and secondary injection targets. The Fourth Panoche is reserved as the tertiary injection zone. Currently, using the Fourth Panoche as an injection zone is unlikely. Final well schematics will reflect actual zones selected for injection.*

EPA Evaluation of Response: The responses above are acceptable. EPA will evaluate the final well schematics when they are submitted.

3.6 Monitoring Well Plugging Plan

The proposed plugging and abandonment procedures are described in Section 7.1 of Attachment E (the PISC and Site Closure Plan). The attachment describes generally the procedures CES will use to plug the monitoring wells, including removal of surface fixtures; use of appropriate materials (cements and plugs) for use in CO_2 environments; and performance of internal and external MITs and other logs. The application notes that well specific procedures will be developed and submitted prior to starting operations.

The plugging and abandonment procedures are generally satisfactory but, as noted above, monitoring well construction information was not provided. Without well construction details and plugging schematics, the plugging procedures are deficient and cannot be evaluated.

Questions/Requests for CES:

- *Please provide proposed construction details and plugging schematics for each of the monitoring wells.*

- *Please refer to Appendix B in this document for updated well schematics.*

EPA Evaluation of Response: This response is partially acceptable. However, cement plugs should be placed at the base of the USDW in the OBS-1 and ACZ 1 wells, similar to the recommendation for the injection well.

Follow-up Question/Request for CES:

- Please add a cement plug in the OBS-1 and ACZ 1 wells at 1,519 to 1,315 feet or extend the plug at the surface casing shoe to 1,315 feet to cover the base of the USDW in the updated plan.

- OBS-1, ACZ-1, and INJ-1 have plug requirements updated in Appendix A below.
- The well construction details, diagrams, and schematics will be updated after pre-operational testing is complete and will be provided in the updated permit application, unless required prior to permit to construct.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *EPA will need to review the plugging procedures based on updated geologic information and construction schematics after the wells are drilled and completed.*

3.7 Corrective Action on Wells in the AoR

Attachment B describes two wells within the AoR that penetrate the Moreno Shale confining zone: Amstar 1 (drilled into the First Panoche Sands) and BB Co. 1 (drilled to basement rock). The Attachment describes the five wellbores located within the AoR and the condition of the two deficient wellbores.

The attachment describes the process by which CES identified wells within a 2.5-mile radius of the proposed injection well, determined which wells penetrate the Moreno Shale confining zone, and reviewed drilling and abandonment records for the wells that penetrate the confining zone. It appears that CES used appropriate methods to identify all artificial penetrations throughout the AoR and the list of artificial penetrations is complete (see the AoR modeling report for additional information).

Attachment D describes the plugging procedures for the Amstar 1 and BB Co 1 wells (the two wells that require corrective action). Figures 14 and 15 from Attachment B are inserted below to illustrate the wellbore condition after the plugging procedure is completed in each wellbore.

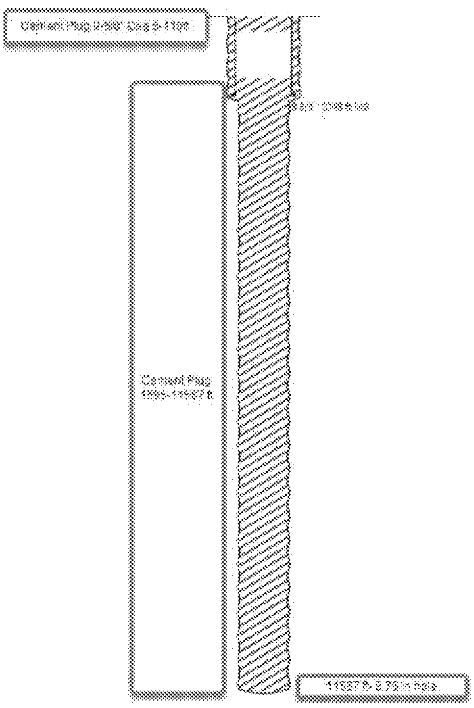


Figure 14: BB Co. 1 wellbore after P&A operation

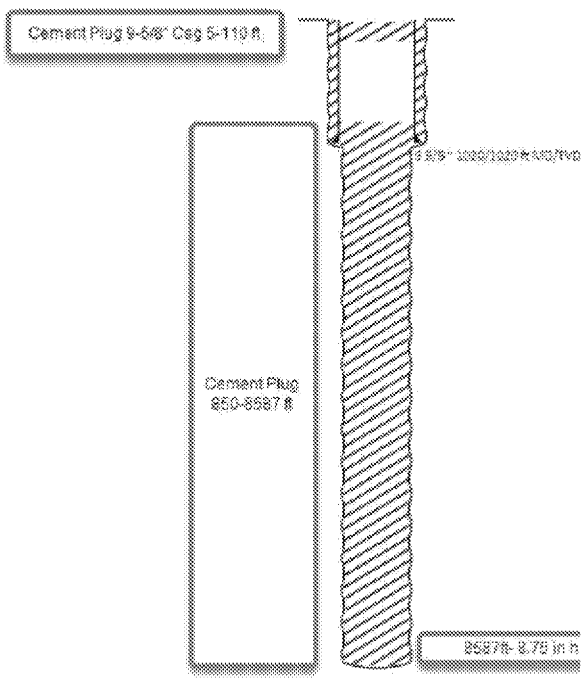


Figure 15: Amstar 1 wellbore after P&A operation

The Amstar 1 and BB Co 1 wells currently have only one relatively shallow casing installed (the Amstar 1 has a cemented surface casing at 1,020 feet and the BB Co 1 has a cemented surface casing at 1,745 feet). Each well was drilled much deeper but no production casing was installed and instead each was open-hole plugged and abandoned, meaning just a small plug of cement is present inside each well's drilled production hole. CES proposes to re-enter these two wells, drill out these plugs, and re-plug them. Under the CES proposed plan, the two wellbores would be filled with Class G cement from total depth upward into the surface casing and from 110 to 5 feet inside the surface casing. It is unclear why CES is proposing the use of Class G cement, instead of a CO_2 corrosion-resistant cement. The depth to the base of USDWs in each well is not provided.

- *The Amstar and BB Co 1 well plugging operations will be corrected to reflect CO_2-resistant cement.*

EPA Evaluation of Response: This response is acceptable. EPA will evaluate the final plugging schematics when they are submitted with the updated AoR and Corrective Action Plan that will be submitted after the well is constructed and pre-operational testing is complete.

Follow-up Question/Request for CES:

- The depth to the base of USDWs should be located in each wellbore and a 200-foot cement plug should be placed across the USDW base if it is located within the uncemented portion of the surface casing.

CES proposes to re-plug and abandon the Amstar 1 well prior to injection operations because it is located within 1.5 miles of the proposed injection well while the BB Co 1 well is located more than 2.32 miles from the proposed injection well and beyond the modeled AoR. The schedule for re-plugging the BB Co 1 well is not provided except that it will be scheduled second to the Amstar 1 well.

- *Because Amstar 1 (1.4 miles from Mendota INJ 1) is much closer to the injection well than BB Company 1 is (2.14 miles from Mendota INJ 1), Amstar 1 will be plugged first because it is of higher risk. Both wells will be plugged prior to commencement of any injection activity at the Mendota INJ 1 well location.*

EPA Evaluation of Response: This response is acceptable.

Questions/Requests for CES:

- *The deepest USDW (calculated at ~1,609feet bgs) is 5,700feet above the Moreno Shale which is the secondary confining zone, as stated in the application. Please provide the depth to the base of USDWs in each of the two wells to be re-plugged and abandoned for corrective action.*

- *Because of the lack of site-specific data, for the time being, the depth of the deepest USDW is estimated to be the same for both wells. There is not enough data to support location-specific USDW depths in the area. The calculations for the depth of the deepest USDW will remain uncertain until more precise methods for calculating this are available from the drilling of a characterization well which will use fluid samples and formation salinity calculations from modern logs.*

EPA Evaluation of Response: This response is acceptable at this point in the project. EPA will evaluate the final plugging schematics based on a definitive determination of the depth to the USDW when they are submitted with the updated AoR and Corrective Action Plan.

- *Please clarify whether CES proposes to re-plug and abandon the BB Co 1 well prior to commencement of injection activities.*

- *CES proposes to replug and abandon the BB Company 1 well prior to commencement of injection activities.*

EPA Evaluation of Response: This response is acceptable.

- *The plugging procedures for Amstar 1 and BB Co 1 on pages 25 and 26 reference a casing diameter of 9 5/8 inches; however, figures 14 and 15 show that the hole is 8.75 inches. Please clarify the discrepancy.*

- *This is correct. The 9 5/8-in. surface casing has drift inner diameter of 8.75 in. Therefore, an 8.75-in. hole was drilled below the 9 5/8-in. casing.*

EPA Evaluation of Response: This response is acceptable.

- *Given that the Amstar 1 and BB Co 1 wellbores may eventually come into contact with the injected CO2, use of a CO2 corrosion-resistant cement will be required.*

- *Comment noted. Attachments and plans will be corrected accordingly.*

EPA Evaluation of Response: This response is acceptable at this point in the project. EPA will evaluate the final plugging schematics when they are submitted with the updated AoR and Corrective Action Plan.

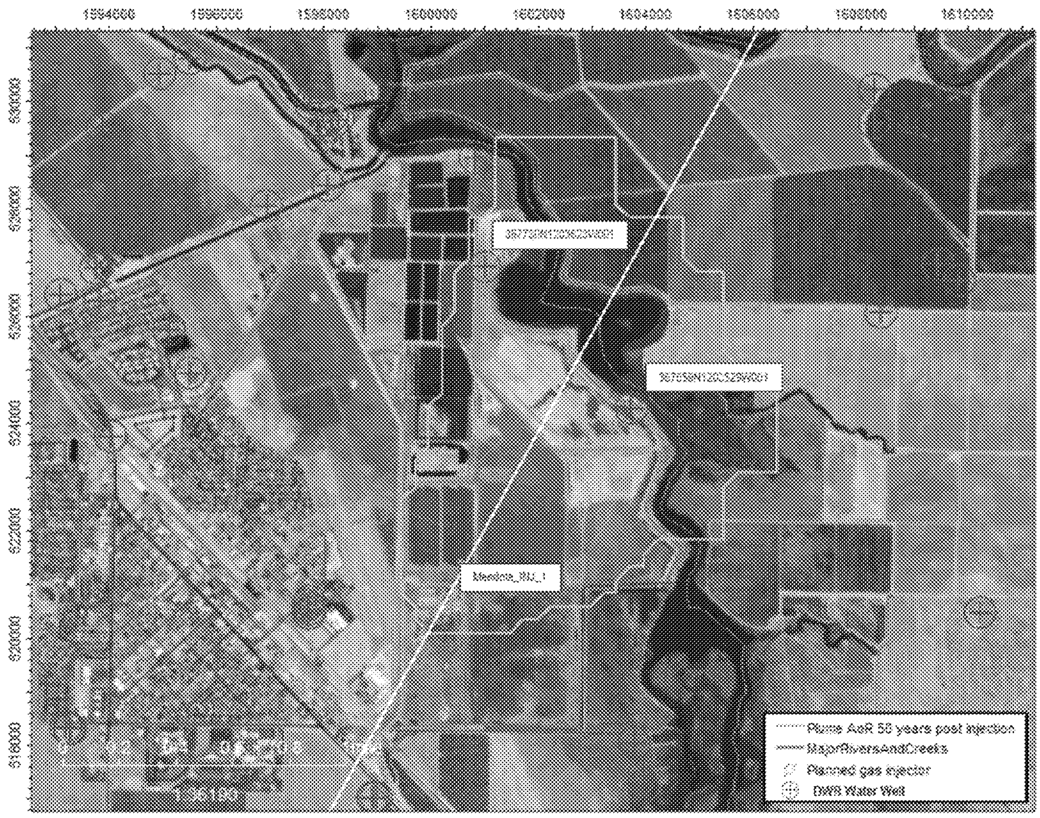
- *Figure 46 of the permit application narrative shows the centroids of the water well locations. Please provide verified actual locations of the water wells.*

- *Please refer to Error! Reference source not found. in Appendix A of this document for surface* locations of *GW1 to GW4 shallow monitoring wells. These are the proposed monitoring well locations that will be drilled.*

EPA Evaluation of Response: It is assumed this refers to Table 4-4 and/or Figure 4-1. However, EPA's question refers to the verified locations of water wells in the AoR.

Follow-up Question/Request for CES:

- EPA requested the verified locations of water wells in the AoR (and not the locations of monitoring wells, which it appears that Table 4-4 and Figure 4-1 show). Please provide this information.
  - Water well locations have been revised based on information found in the California Water Data Library (WDL) Station Map. Within the AoR, there are two DWR water wells (labeled as "use: irrigation", 367730N1203623W001 and 367659N1203529W001), shown in Figure 16 below (California Department of Water Resources, 2021).



- Figure 16: Water wells in the AoR. (California Department of Water Resources, 2021)

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The AoR modeling and corrective action evaluation will need to be reviewed based on confirmation of the thicknesses and depths of the injection and confining zones and the depth of the lowest USDW at the project site through seismic imaging and information gained during drilling of the injection well and deep monitoring well.*
- *Comment noted. CES intends to update all models and mitigation activities based upon subsurface confining zone depth and thickness information as it becomes available as a product of remotely acquired and direct measured geologic and geophysical data sets.*

EPA Evaluation of Response: This response is acceptable at this point; EPA will evaluate the updated AoR and Corrective Action Plan when it is submitted after pre-operational testing is complete.

ENCLOSURE 5

Evaluation of Applicant Responses to EPA's Technical Review Comments on the Testing and Monitoring Plan in the CES-Mendota Class VI Permit Application

EPA reviewed responses provided by Clean Energy Systems (CES) to EPA's questions about the CES- Mendota Class VI UIC Permit. EPA's Technical Review Comments and recommendations (dated October 28, 2020) are in blue text. CES's responses (dated November 2, 2020) are provided in green text. EPA evaluations are in red text. EPA expects that all of these questions can be addressed based on available information, i.e., prior to construction authorization. No confidential business information is included in this document.

Evaluation of Proposed Testing and Monitoring Activities at the CES-Mendota Class VI Project

This testing and monitoring evaluation report for the proposed Clean Energy Systems (CES)-Mendota Class VI geologic sequestration project summarizes EPA's evaluation of the testing and monitoring CES proposes to conduct during and following injection operations. Due to the similarities of certain monitoring activities (e.g., groundwater monitoring and plume and pressure front tracking) to be performed in the injection and post-injection phases, these activities (as described in Attachments C and E of the Class VI permit application) are evaluated in a single report. This review also identifies preliminary questions for CES.

CES notes that they will report the results of all injection-phase testing and monitoring activities in compliance with the requirements of 40 CFR 146.91. The results of post-injection testing and monitoring results will be submitted to EPA in annual reports within 60 days following the anniversary date of the date on which injection ceases.

1.1 Carbon Dioxide Stream Analysis

CES will sample the carbon dioxide (CO_2) stream on a quarterly basis at a location after the last stage of compression. The table below summarizes the analytical parameters that CES proposes for monitoring the CO_2 stream (from Table 1).

Parameter	Analytical Method(s)[1]
Oxygen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 GC/DID GC/TCD
Carbon Monoxide	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Ammonia	ISBT 6.0 (DT)
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
CO_2 Purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

There are no EPA-approved analytical methods for CO_2 injection streams. The analytical methods CES proposes to use appear to be from the International Society of Beverage Technologists (ISBT). All of these analytical methods, except ISBT 6.0 have been employed for other CO_2 GS projects, so there is EPA precedent for their use in EPA Class VI permits.

Most of the proposed analytical parameters match the results of a gas stream analysis that is presented in Table 8 of the permit application narrative (replicated below). The application notes that the gas stream will contain 96.78% CO_2 with some impurities. It is unclear when this sample was taken.

Injectate Composition (Mass Fractions) From Table 8 of the permit application	
H2O	0.002245
O2	0.011536
H2	0.000164
N2	0.001475
CO	0.005322
CO2	0.967834
Ar	0.01119
NO	9.01E-05
NO2	9.03E-08
H2S	0.000144
NH3	1.93E-10

QA procedures for all of the analytical parameters proposed for the CO_2 stream analysis are documented and described in the QASP (Section A4a). Two additional parameters related to injectate analysis are mentioned in some portions of the QASP: total hydrocarbons (THC, ppm v/v as CH4) and sulfur dioxide (SO_2, ppm v/v). For example, they are mentioned on pages 21 and 35 but are not included in the summary of analytical parameters for the CO_2 stream in the QASP (Table 6).

Questions/Requests for CES:

- *In addition to the proposed injectate analytical parameters identified in Table 1 of the Testing and Monitoring Plan, argon and H_2 were detected in the analytical sample described on Table 8 of the permit application narrative. Please include these in the Testing and Monitoring Plan or explain why analyses for these parameters is not warranted.*

- *Ar and H_2 will be added to the testing and monitoring plan (Table 1 of Attachment C) based on the current CO_2 injectate composition. The injectate analytical parameters shown in the testing and monitoring plan (Table 1 of Attachment C) will be updated according to the final CO_2 injectate composition approved by EPA prior to injection.*

- *Total hydrocarbons and sulfur dioxide (SO_2) are mentioned as part of the QA procedures for injectate analysis in the QASP, but they are not on Table 1 in Attachment C. If these are not to be part of the injectate analysis, please remove them from the QASP.*

- *Total hydrocarbons and sulfur dioxide were included in the QASP as part of the QA procedures and are not relevant to injectate analysis. They have been removed from the QASP.*

- *What is the date of the injectate characterization sample presented on Table 8 of the permit application narrative? EPA will require another baseline injectate sample be analyzed prior to commencement of injection.*

- *The composition of the CO_2 stream shown in Table 8 of the permit application narrative is based on a process model completed in December 2019. Baseline injectate samples will be collected and analyzed. The results will be submitted to the EPA for approval prior to injection.*

EPA Evaluation of Responses: The above responses are acceptable; EPA will confirm the revisions when the updated Testing and Monitoring Plan is submitted.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If the geochemical modeling evaluation indicates that any injectate constituents may lead to* geochemical reactions that could affect operations or change aquifer properties, additional analytical parameters for the injectate analysis may be warranted.

- *If the geochemical modeling evaluation indicates potential geochemical reactions or impact to the aquifer, additional parameters will be requested to be added to the analysis.*

EPA Evaluation of Response: The response is acceptable. EPA will confirm that the plan has been updated to reflect this response when CES submits the revised plan.

1.2 Injection Well Testing

The subsections below describe the planned quarterly corrosion monitoring; continuous recording of injection pressure, rate, and volume to evaluate internal mechanical integrity; and annual external MITs that will meet the requirements at 40 CFR 146.90(b), (c), and (e).

2.2.1 Corrosion Monitoring

CES proposes to conduct corrosion monitoring using the coupon method. The coupons will be exposed to conditions similar to those in the borehole, in a parallel flow-through pipe arrangement containing the stream of high-pressure CO_2 at a location downstream of processing equipment and just upstream of actual injection into the well. According to CES, the samples will be handled and assessed in accordance with ASTM G1-03. The coupons will be inspected prior to testing and will be removed and inspected on a quarterly basis. Inspection equipment will be able to dimensionally measure at a tolerance of 0.0001 inches, to weigh at a tolerance of 0.0001 gram, and to photograph or visually inspect at a level of at least 10X magnification.

The proposed coupons will be composed of the materials summarized in Attachment C, Table 5, as excerpted below:

List of equipment coupons with material of construction (Table 5 of Attachment C)

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
'Long String Casing	Carbon Steel
Long String Casing	Chrome Alloy
Injection Tubing	Chrome Alloy
Wellhead	Chrome Alloy
Packer	Chrome Alloy

The materials identified for corrosion monitoring were compared to the list of proposed construction materials for the injection well, Mendota_INJ_1, and are shown in Attachment G, Table 2, *Casing Specifications,* Table 3, *Packer Specifications,* and Table 4, *Injection Tubing Specifications,* and excerpted below:

Casing specifications (Table 2 of Attachment G)

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight <lb ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr op)	Burst Strength (psi)	Collapse Strength <psi)
Conductor	86	22	21	197.41	B	Welded	26.13	2440	1950
Surface	1800	16	15.01	84	N80	Long	26 13	4330	1480
Intermediate	7432	10.75	9.760	55.5	N80	Long	26 13	6450	4020
Long-string	7332	7	5.920	38	T-95 Type 1	Long	26.13	12830	13430
Long-string	10412	7	5.920	38	TN 95Cr13	Long	14.92	12830	13430

As noted in Table 2 of Attachment G, the conductor, surface, and intermediate casing will be composed of carbon steel, grades B and N80. The long-string casing will be composed of alloy steel, grades T-95 and TN 95, containing relatively high chrome content.[1]

It appears that the carbon steel composition of the coupon for corrosion monitoring of the long-string casing (surface) in Table 5 (from Attachment C) is not representative of the materials, both chromium alloy steels, identified for the long-string casing in Table 2 (from Attachment G). It is not clear if the long-string casing (surface) listed in Table 5 would in fact be used at depth, given its label, and an equivalent surface long string casing is not listed in Table 2 of Attachment G.

- *TN 95Cr13 is the proprietary grade for a tubing manufacturer (Tenaris) for a martensitic stainless steel with a 13% chrome content consistent with an L80-type 13% chrome material but modified for higher strength. As such, it is considered a chrome alloy. Please refer to Tenaris' website for further information (https://www.tenaris.com/en/products-and-services/octg/steel- grades).*
- *T-95 Type 1 is standard API grade nomenclature for API defined tubulars in API 05CT.*
- *There is an error on the long-string equipment coupon description in Table 5 of Attachment G and has been corrected. See Table 4-1 in Appendix A of this document for the updated table.*

EPA Evaluation of Response: The response is acceptable.

Tubing specifications (Table 3 of Attachment G)

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	9430	3.5	2.992	9.2	L80Cr13	Long	10160	10540

The proposed injection tubing for the injection well will be composed of L80Cr13, or Cr13L80, an alloy steel with high chromium content, for which the proposed coupon in Table 5 is representative.

Packer specifications (Table 4 of Attachment G)

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Super 13Cr	9300	64	38	5.685	4.0

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
133.12@250degF	5000	5000	6000	5.949

[1] https://www.contallov.com/products/grade/t95
https://metals.ulprospector.com/datasheet/e226076/tenaris-tn-95cr13

Similarly, the coupon proposed in Table 5 for the packer is representative of the Super 13Cr steel alloy proposed for the packer in the injection well.

Although the materials of construction for the pipeline and wellhead are not described in Attachment G, it is assumed that coupons would be selected to represent these materials.

In addition to the corrosion monitoring described above, CES proposes to perform casing inspection logs (CILs) to measure the thickness of the injection well casing at the subsurface (as described on page 17 of Attachment C, and on pages 15 and 18 of Attachment G). (See also the summaries of MITs in Tables 5 and 6 of Attachment G.) The proposed CIL would be performed prior to injection, and at one year intervals thereafter. CES proposes the following logging tools for this testing: ultrasonic imaging (PowerFlex), magnetic flux leakage (MFL), casing bond log (CBL) and electro-magnetic imaging (EMIT). A reduction in thickness of more than 20% of API standard thickness would prompt further investigation.

Questions/Requests for CES:

- *Please revise the list of casing strings and materials in Attachment C, Table 5 to reflect Attachment G, Table 2, Casing Specifications. For example, please provide a coupon material representative of long string casing (surface) e.g., chrome alloy.*

- *Please refer to Appendix A, Table 4-1, for the list of equipment coupons with material of construction. (This is the updated Table 5 of Attachment G).*

EPA Evaluation of Response: The updates in Appendix A, Table 4-1 of the response now match Attachment G, Table 2; the response is acceptable.

- *Please provide the list of construction materials to be used for the pipeline and wellhead so that they can be compared to the proposed coupon materials for the corrosion testing program.*

- *The construction materials for the pipeline will be defined during FEL-2 study and will be provided to the EPA when available. The construction material for the wellhead will have a body of low-carbon-alloy 4130 steel with inlays covering the internal CO_2 wetted surfaces, and the wellhead will be constructed per NACE MR0175/ISO 15156 guidelines. Currently, that is thought is to be a martensitic stainless steel 13Cr but is dependent on the final CO_2 stream composition and testing.*

EPA Evaluation of Response: The response is acceptable. This content should be reflected in updates to the construction plan following the completion of construction activities.

2.2.2 Continuous Monitoring to Evaluate Internal Mechanical Integrity

CES proposes continuous monitoring of temperature and pressure via gauges at three locations within the injection well: (1) at the surface, (2) in the tubing at the packer, and (3) from the surface to the tubing packer, via distributed temperature sensing (DTS) fiber. The continuous monitoring program is summarized in Table 2 of Attachment C, as excerpted below.

Monitoring Injection Rate and Pressure: injection rate and pressure will be monitored via the electronic temperature/pressures gauges connected to the distributive control system (DCS). The DCS will ensure that maximum pressure of **2,026 psi** at the surface and of **5,677 psi** at the bottom hole are not reached.

Monitoring Annular Pressure: the annulus will be filled with brine during injection operations. During injection, the surface injection pressure should always be at least **1,142 psi,** as noted on page 14 of Attachment C. During shutdown, the surface annulus pressure must maintain the 100 psi difference between the annulus and the casing. The proposed annulus monitoring system, composed of the continuous pressure gauge, the head tank, two sets of pressure regulators, and a flood level indicator, will maintain an annulus pressure between **1,100 and 1,200 psi** (see page 14 of Attachment C).

Table 2: Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	**Device(s)**	**Location**	**Min. Sampling Frequency**	**Min. Recording Frequency**
Injection pressure		Surface	10 seconds	5 minutes (3)
Injection pressure		Reservoir - Proximate to packer	10 seconds	5 minutes (3)
Injection rate		Surface	10 seconds	5 minutes (3)
Injection volume		Surface	10 seconds	5 minutes (3)
Annular pressure		Surface	10 seconds	5 minutes (3)
CO_2 stream temperature		Surface	10 seconds	5 minutes (3)
Temperature		Reservoir - Proximate to packer	10 seconds	5 minutes (3)
Temperature/Acoustic	DTS/DAS	Along wellbore to packer	10 seconds	1 hour
Annulus fluid volume		Surface	4 hour	24 hour

It appears that the annulus pressure of **2,126 psig** proposed in the Table of Injection Well Operating Conditions, in Attachment A is higher than the range of pressures, of **1,100 psi to 1,200 psi,** to be maintained in the annual pressure monitoring system described in the Testing and Monitoring Plan (see bottom of page 14 of Attachment C).

Questions/Requests for CES:

- *Please describe more explicitly the location/depth of the pressure/temperature gauges at the packer.*
- *Please refer to Figure 5-1 in Appendix B for a well schematic that includes gauge placement and type.*

EPA Evaluation of Response: The schematic in Figure 5-1 shows the locations of temperature, acoustic, and pressure gauges at the depths of the USDW, above the confining zone, and in the Panoche (consistent with the Testing and Monitoring Plan). This response is acceptable.

- *Please explain the discrepancy between the annulus pressure to be maintained in the annulus monitoring system, of 1100 psi to 1200 psi, and the proposed operating annulus pressure of 2126 psi in Attachment A.*

- *The operating annulus pressure of 2126psi is in error and should be 5777psi. Monitoring annular pressure conditions at surface pressure of500 psi will be initiated. This will be achieved by using a packer fluid of 10.9 pound per gallon (ppg) which would give a pressure of5277 psi at the top of the packer. One of the purposes of the packer fluid is to kill the well quickly in the event of an uncontrollable leak. It is important to have a packer fluid with sufficient density to kill the well. Because this is an injection well there is potential for higher pressures than pore pressure coming back into the well, at least temporarily. For purposes of the permit, CES is assuming* maximum injection pressure of 5677 psi. This means the packer fluid would need to be 10.9-ppg density with 500 surface pressure. A sustained 500 psi surface pressure is considered an optimal pressure for monitoring pressure at surface. Higher pressures create potentially more safety and operational risks. A 500 psi annular pressure will allow adequate monitoring of the expansion and contraction of the annular fluid due to temperature changes especially during injection. Potential annular fluid losses due to leaks and gas invasion from tubing or packer failure will be visible monitoring the 500 psi wellhead pressure. After an evaluation well is drilled, more comprehensive values can be given for pressures.

EPA Evaluation of Response: This response is acceptable.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *The maximum pressure thresholds identified for continuous monitoring and the annulus pressure in Attachment C may need to be adjusted based on the determination offinal permit conditions.*
- *Comment noted. This will be reviewed when official permit conditions are provided.*

EPA Evaluation of Response: This response is acceptable at this time.

2.2.3 External MITs

As described in the pre-operation testing plan in Sections 4 and 5 of Attachment G, in addition to deviation checks to be conducted during well construction, CES proposes to perform MITs in both the injection well and the deep monitoring wells (ACZ_1 And OBS 1, which are described in the section on Groundwater Quality Monitoring below), in compliance with the regulatory requirements as summarized in Tables 5 and 6 of Attachment G, excerpted below.

Summary of the Mendota_INJ_1 MITs and pressure fall-off tests to be performed prior to injection (Table 5of Attachment G)

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	Pressure test	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Pressure test	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Casing inspection Ultrasonic and CBL	Prior to operation
40 CFR 146.87(e)(1)	Testing prior to operating	Pressure fall-off test	Prior to operation

MITs to be performed on the deep monitoring well(s), MendotaOBS 1 and Mendota ACZ 1 (Table 6 of Attachment G)

Rule Description	Test Description	Program Period
MIT - Internal	Pressure test	Prior to operation
MIT - External	Pressure test	Prior to operation
MIT - External	Casing inspection, EMIT, MFL, Ultrasonic and CBL	Prior to operation
Testing prior to operating	Pressure fall-off test	Prior to operation

During injection operations, CES proposes conducting at least one of four MITs to confirm external mechanical integrity as summarized in Attachment C, Table 8, which is excerpted below. (Note that, per 40 CFR 146.89(c), at least one of the MITs must be an approved tracer survey such as an oxygen- activation log or a temperature or noise log, unless an alternate test is approved by the EPA Administrator.)

- *Comment noted. Approved tracer surveys are planned to be run per Table 8 of Attachment C, mechanical integrity testing (MIT).*

EPA Evaluation of Response: This response is acceptable.

Table 8: Mechanical integrity testing (MIT).

Test Description	Location
Temperature Log / Survey	Along wellbore using Distributed Temperature Sensing (DTS) or conventional wireline well log
Oxygen Activation Log	Wireline Well Log
Pulsed Neutron Logging	Wireline Well Log
Acoustic (or Noise) Log/Survey coupled with Temperature Log/Survey	Along wellbore using Distributed Acoustic Sensing (DAS); DAS equivalent or conventional wireline well log

Oxygen activation logging, temperature logging, or acoustic (or noise) logging procedures are described in Attachment C, Section 7.2.1.3 (oxygen activation), Section 7.2.1.1 (temperature), and Sections 7.2.1.5 and 7.2.1.6 (noise). In Section 7.2.1.4, CES proposes testing using pulsed neutron logging.

CES proposes performing these tests annually, which is consistent with the Class VI requirements. The proposed pulsed neutron logging would occur, as described on page 23 of Attachment C, on a quarterly basis for 18 months after authorization, and then annually.

Questions/Requests for CES:

- *Please justify the use of pulsed activation logging as an alternative tool, beyond the MITs described at 40 CFR 146.89(c), or clarify in the Testing and Monitoring Plan that at least one of the tests identified at 40 CFR 146.89(c) will be performed each year.*

- *CES proposes using multiple technologies to ensure external mechanical integrity of the injection and monitoring wells to provide the safe operation of the sequestration site and ensure nonendangerment to any USDW. Initial evaluation of the INJ1 injection well and the OBS1 and*

ACZ 1 monitoring wells will be done using casing and cement CBL and ultrasonic logs and pressure tests.

- *The INJ 1 injection well and the OBS 1 and ACZ1 monitoring wells will all be instrumented with DAS/DTS fiber and monitored continuously throughout the injection period. The distributed temperature and acoustics are to be evaluated over the reporting period for the monitoring wells. The temperature and acoustic (noise) survey for the INJ 1 injection well may be obscured by the injection operation. The INJ 1 injection well will be shut in, and a temperature and acoustic (noise) survey will be acquired quarterly during the first 1.5 years of injection and annually through the injection period. See Table 4-2 in Appendix A of this document.*
- Pulsed neutron logs (PNL) have several measurements sensitive to CO_2 and can detect CO_2 in the formation and well annular spaces. PNL measurements can be made through multiple tubing and casing strings allowing monitoring of the well annuli and formation behind the completion tubing. This sensitivity, especially in time lapsed monitoring, allows detecting CO_2 introduction, change, or accumulation in the well annuli and associated to analyze mechanical integrity and assist in plume migration modeling. Additionally, PNL thermal decay (sigma) measurements are sensitive to salinity changes and can detect migration of water in the well annuli and formations. PNL logs will be acquired in the INJ 1 injection well.
  See Table 4-2 in Appendix A of this document. OBS 1 and ACZ 1 monitoring wells will be monitored quarterly during the first 1.5 years of injection and annually through the injection period.

EPA Evaluation of Responses: The responses in this section are acceptable.

2.3 Pressure Fall-Off Testing

CES described nearly identical PFOT procedures in the Testing and Monitoring Plan and in the Construction Plan (Attachment G). See the construction and plugging evaluation report for the results of our review of the PFOT procedures. At the conclusion of the reviews, the Testing and Monitoring Plan will need to be revised to address any issues identified.

Questions/Requests for CES:

- The testing and monitoring plan quotes the Class VI Rule requirement that a PFOT be performed at least every 5 years. It also states (under "Timing of Falloff Tests and Report Submission ") that falloff tests must be conducted annually. Please clarify the planned frequency of PFOTs during the injection phase.

- PFOT testing will occur every 5 years. The timing of falloff tests and report submissions will be updated accordingly.

EPA Evaluation of Response: The response is acceptable.

2.4 Groundwater Quality Monitoring

CES plans to monitor groundwater quality above the confining zone using direct and indirect methods. ***Direct Groundwater Quality Monitoring***

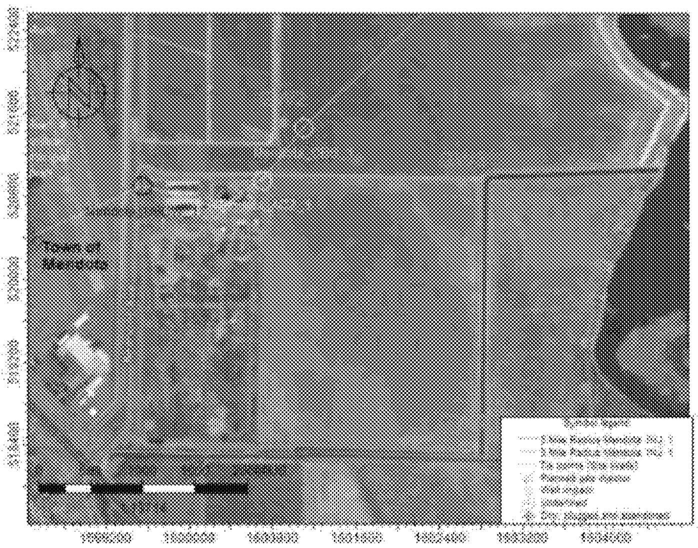
CES plans to perform direct groundwater quality monitoring via four (4) shallow groundwater monitoring wells (GW1, GW2, GW3, and GW4), a USDW monitoring well (USDW1), and an above confining zone monitoring well (ACZ1).

The approximate locations of the monitoring wells are shown on the map on the left in the figure below (from Figure 1 of Attachment C). The locations are preliminary and are expected to be refined as the project develops.

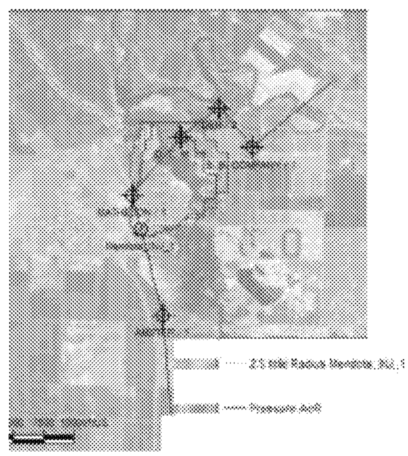
- GW1, GW2, GW3, and GW4 are shallow groundwater monitoring wells used to monitor the quaternary/shallow aquifers around the site that are sources of drinking water. CES plans to sample in one interval. The precise depths of these groundwater monitoring wells will be determined when the groundwater characteristics of the site are better understood, but they are expected to be somewhere between 50 and 500 feet deep.
- Mendota USDW 1 will be used to sample from the Santa Margarita or the base of the USDW, and it will be located within 1,000 feet of the injection well.

The ACZ1 monitoring well will be completed in the Garzas Formation or the first permeable sandstone above the Moreno Shale (confining zone). The well will be in the up-dip direction of the Moreno Formation, or in the event a potential fault is identified on the 3D seismic within the AoR CES states that "the well will be in the direction of the fault intersection of the Moreno formation."

- In addition, the Mendota OBS 1 monitoring well will be completed in the Panoche Sand and will be used to monitor plume migration. See "CO2 Plume Monitoring," below.



Location of monitoring wells



Delineated AoR

The map of monitoring well locations can be compared to the expected extent of the plume after 20 years, as shown on the map to the right of the figure above (from Figure 12 of Attachment B). While the scales of the maps in the plans are different, they have the same legend and it appears that the monitoring wells will be located within the defined AoR and in the anticipated direction of plume and pressure front movement. The suitability of these proposed locations will be refined as the AoR modeling evaluation proceeds.

CES indicates that the precise locations of the wells will be determined in future phases of the project (it is unclear what this means relative to construction of the injection well and pre- operational testing). However, the location and construction of the wells will need to be approved prior to issuing a Class VI permit. This is typically included with the permit to construct the injection well; if this is not possible, the permit will need to include conditions such that authorization to inject cannot be given until a separate review of the monitoring well locations and their construction is performed. CES should note that the Central Valley Water Board indicated that any newly drilled monitoring wells must be approved by the Water Board and, while existing wells would not need to be approved, the Water Board expressed interest in any plans to use existing wells as monitoring wells.

Groundwater quality monitoring above the confining zone will include baseline monitoring and monitoring during the injection and post-injection phases of the project:

- Baseline fluid sampling at the shallow monitoring wells (GW1, GW2, GW3, and GW4) and USDW 1 will occur quarterly for at least one year prior to injection.
- Baseline fluid sampling at Mendota ACZ 1 will occur during well construction and once prior to injection.
- Injection phase groundwater quality sampling and monitoring will be performed quarterly in GW1, GW2, GW3, GW4, and USDW 1 and annually in ACZ 1
- During the post-injection phase, monitoring in GW1, GW2, GW3, GW4, and USDW 1 will be quarterly for 3 to 5 years post-injection and then annually afterwards. Monitoring in ACZ 1 will be annual for years 1 through 3, then in years 5, 7, and 10 after injection ceases.

Table 6 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining

Table 7 of the Testing and Monitoring Plan (replicated below) identifies the analytical and field parameters for groundwater sampling above the confining zone. CES proposes to analyze for the same parameters in Table 2 of the PISC and Site Closure Plan. Groundwater quality analytical methods are all EPA-approved Methods and are addressed in the QASP.

The parameters appear to be appropriate for groundwater quality monitoring needs for GS projects, and are consistent with other Class VI monitoring programs. It is recommended that CES add zinc to the groundwater quality monitoring parameters to complement the monitoring of other commonly occurring heavy metals (Cu, Pb, Cr, Co). Note that, as additional information is gathered based on the reviews of other parts of the permit application or pre-operational data collection, recommendations or requirements for additional analytical parameters may be provided.

Parameters	Analytical Methods [1]
Quaternary / Shallow strata sources of drinking water	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn, and Tl	1CP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0 '
Dissolved CO2	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; Method 2540 C [11
Alkalinity	Method 2320 B m
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [11
Temperature (field)	Thermocouple
Santa Margarita or base of USDW	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0 '
Dissolved CO2	Coulometric titration, ASTM D513-11
Isotopes: 5^{13}C of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; Method 2540 C [11
Alkalinity	Method 2320 B [11
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [11
Temperature (field)	Thermocouple
Garzas	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0 '
Dissolved CO2	Coulometric titration, ASTM D513-11
Isotopes: 5^{13}C of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; Method 2540 C [11
Alkalinity	Method 2320 B [11
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [11
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

2.5 Indirect Groundwater Quality Monitoring

Indirect groundwater quality monitoring activities above the confining zone will include DAS (distributed temperature/acoustic) monitoring and pulsed neutron monitoring in ACZ 1, OBS 1, and INJ 1 (the injection well). Following a baseline log, DAS monitoring will be continuous throughout injection phase and during the first three years of post-injection phase monitoring.

Questions/Requests for CES:

- *Please provide a map that shows the location of the monitoring wells at a scale that also shows the extent of the plume and pressure front (i.e., Figure 12 of Attachment B and Figure 1 of Attachment C at the same scale)*
- *Please refer to Figure 4-1 in Appendix A in this document, which is the replacement map combining maps from Figure 12 Attachment B and Figure 1 Attachment C.*

  EPA Evaluation of Response: The map has been provided as described. It is understood that the monitoring well locations are preliminary, and the final locations will depend on the final site characterization data, updated modeling, and findings about the transmissive nature of any faults based on 3D seismic surveys. The final locations of the wells will be evaluated based on this information.

  Follow-up Question/Request for CES:

  - EPA requests that Figure 4-1 be included in the updated Testing and Monitoring Plan to enhance clarity.
    - Figure 4-1 will be included in the updated Testing and Monitoring Plan.

- *Table 6 indicates that quarterly monitoring in the shallow wells and USDW1 will occur in years 1 and 2 of the injection phase. Please also specify the proposed frequency at which groundwater sampling will be performed in the remaining years of the injection phase.*
- *Please refer to Table 4-2 in Appendix A of this document, which updates the groundwater monitoring schedule from Table 6 in the original submission.*

  EPA Evaluation of Response: The table has been provided as described. The response is acceptable.

- *EPA requests that CES include quarterly monitoring in ACZ1 in Table 6 (at least for the first 5 years of injection) since this is a porous formation right above the confining zone and is close to the injection well. Please revise Table 6 accordingly.*
- *Refer to Table 4-2 in the Appendix of this document, which updates Table 6 to reflect the change from continuous to quarterly monitoring for the first 5 years of injection.*

  EPA Evaluation of Response: The table has been provided as described. The response is acceptable.

- *Please remove DAS and pulsed neutron monitoring from Table 6, as these are not groundwater monitoring techniques.*
- *For clarity, the table has been divided into groundwater (shallow groundwater and deepest USDW) monitoring techniques and well integrity monitoring (above confining zone). See Table 42* in Appendix A of this document, which is the updated Table 6.

  EPA Evaluation of Response: The table has been edited as described. The response is acceptable.

- *Please add zinc to the groundwater quality monitoring parameters in Table 7 to complement the monitoring of other commonly occurring heavy metals (Cu, Pb, Cr, Co).*
- *Zinc (Zn) has been added to the pertinent locations in Table 7 as requested.*

EPA Evaluation of Response: The table has been edited as described. The response is acceptable.

- *Please analyze the d^{13}C of the injectate and include it among the injectate testing parameters.*
- *Comment noted. d^{13}C has been added to Table 1 of the Testing and Monitoring Plan.*

EPA Evaluation of Response: The updated Table 1 (injectate analysis) is not included in the response; EPA will confirm the addition of d^{13}C to the table when the updated Testing and Monitoring Plan is submitted. The response is otherwise acceptable.

- *EPA will require including water density in the ACZ1 monitoring parameters to allow comparisons of water quality monitoring parameters above and below the confining zone and to support understanding of fluid density in the USDW for calculation of the critical pressure.*
- *Water density sampling as part of a larger fluid sampling protocol has been added to Table 4-2 in Appendix A of this document (the updated original Table 6).*

EPA Evaluation of Response: See the follow-up request below.

Follow-up Question/Request for CES:

- Table 4-2 of Appendix A relates to monitoring activities and locations and does not appear to include water density. EPA requests that water density be added to Table 7 of the Testing and Monitoring Plan.
- Table 4-2 refers to the schedule for monitoring activities. Water density will be added to Table 7 in the Testing and Monitoring plan.

- *Please explain the sequence of events regarding data collection (i.e., seismic and water quality evaluations and updated AoR modeling) and the determination of monitoring well placement and depths. It is not clear based on the Testing and Monitoring Plan how CES proposes to collect the data to inform proposed monitoring well placement.*

- *3D seismic data will be acquired and incorporated to assist with defining the subsurface. This information will be used to refine and inform the existing AoR model. The placements of the monitor and injection wells will be reviewed and validated based on the updated AoR model prior to drilling the well. As well data are acquired, the AoR model will be updated, and the remaining monitor well placement will be reviewed and updated accordingly.*

- *CES plans to use shallow groundwater wells (GW1, GW2, GW3, and GW4) sampled on a quarterly baseline schedule. The deeper monitoring well (USDW 1) will be drilled and then sampled quarterly for a 1-year baseline period. These wells are planned on the edges of the CES property. These wells will likely be drilled and sampled before the 3D seismic data are acquired and the injection wells are drilled. CES is investigating to confirm if existing groundwater monitor wells exist on the property that can be used for this purpose.*
- *Currently, the deeper the CO_2 injection well (INJ1) and the deeper monitoring wells (OBS1 and ACZ1) are located in an optimal location based on the data that are currently available (2D seismic data and the current geological model). The location of the OBS 1 monitoring well is currently planned to be 1100 ft NE of INJ 1. Based on the petrophysical characteristics of the formation, this is a reliable distance, which is designed to observe the breakthrough of CO_2.*
- *The 3D seismic survey will help determine the optimal location for the injection (INJ 1) and monitoring wells (OBS1 and ACZ1). The 3D seismic survey and inversion results will be used to avoid any potential subsurface complexity such as faults or areas of changing reservoir*

conditions. This distance of the OBS 1 well may be closer or farther depending on the results of the 3D seismic survey. The geological model, reservoir simulations, and the AoR boundary will be updated at this time.

- *After INJ1, OBS 1, and ACZ 1 are drilled, the data (formation tops, modern well logs, core analysis, updated petrophysical properties, etc.) will be used to update the geological model, reservoir simulations, and the AoR boundary.*

EPA Evaluation of Response: The response is acceptable.

- *The Testing and Monitoring Plan, on page 17 states that to meet the requirements at 40 CFR 146.95(f)(3)(i), CES will also monitor groundwater quality in the first USDWs immediately* above and below the injection zone(s). The requirement to monitor USDWs below the injection zone only applies to projects operating under injection depth waivers and does not apply to the CES project. Please edit the sentence accordingly.

- *Comment noted. The statement in Attachment C on Page 17 has been updated and reads as follows: To meet the requirements at 40 CFR 146.95(f)(3)(i), Clean Energy Systems will also monitor groundwater quality, geochemical changes, and pressure in the first USDWs immediately above the injection zone(s).*

EPA Evaluation of Response: The response is acceptable.

- *Table 6 of the Testing and Monitoring Plan indicates that fluid sampling will be performed in OBS 1; however, Table 7 does not include Panoche sampling for water quality testing. Please clarify whether the sampling proposed to be performed in OBS 1 is for the purpose of groundwater quality monitoring or plume tracking, and update either Table 6 or Table 7 accordingly.*

- *Table 4-2 in Appendix A of this paper (original Table 6) has been updated to delineate between groundwater quality monitoring and well integrity monitoring testing scenarios.*

EPA Evaluation of Response: See the follow-up question below.

Follow-up Question/Request for CES:

- It is unclear how the activities listed in the bottom half of Table 4-2 in Appendix A demonstrate well integrity (i.e., per 40 CFR 146.89). Should this refer to plume tracking?
  - DAS and pulsed neutron are reservoir characterization tools that will aid in well integrity and plume tracking through CO2 leakage. The title of Table 4-2 will be updated to state both well integrity and plume tracking monitoring technologies.

- *The spreadsheet of proposed testing and monitoring activities submitted with the application indicates that continuous DAS monitoring will be performed in* ***INJ 1;*** *however, this is not included in Table 6 of the Testing and Monitoring Plan. Please clarify the discrepancy.*

- *Continuous DAS monitoring is currently proposed for INJ-1; however, the injection process will create borehole conditions that are too noisy for meaningful DAS acquisition. If acceptable to the EPA, DAS acquisition in INJ 1 will only occur when the well is shut in, using wireline fiber- optics to record the acoustic (noise) log using DAS, as described in section 7.2.1.6 of the Testing and Monitoring Plan.*

EPA Evaluation of Response: See the follow-up request below.

Follow-up Question/Request for CES:

- EPA requests that Table 6 include DAS monitoring for completeness, even if the frequency of monitoring may need to be timed with shut in of the injection well.

- DAS monitoring will be added to Table 6.

- *Please specify the proposed sampling and recording frequencies for continuous DAS monitoring during the injection phase (i.e., include information similar to Table 3 of the PISC and Site Closure Plan in the Testing and Monitoring Plan).*

- *The sampling (10 seconds) and recording (1 hour) frequencies for continuous DAS monitoring have been added to Table 2 of the Testing and Monitoring Plan.*

EPA Evaluation of Response: See the follow-up question below.

Follow-up Question/Request for CES:

- CES indicated in the previous response that DAS monitoring only makes sense during shut- in periods. It is assumed, therefore, that the frequencies in this response would apply during shut-in times, when CES proposes to do the DAS monitoring. Is this correct?
  - This is correct.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If new information or updates to the geochemical modeling based on pre-operational testing raises additional concerns about subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of groundwater quality analytical parameters will need to be revisited to make sure that all relevant parameters are represented. In particular, the list of analytes should be compared against comprehensive groundwater chemistry analyses and information on the mineralogy and whole-rock chemistry of the solids in the injection zone and upper confining zone. This comparison will help finalize the groundwater chemistry analyte list.*
- *Comment noted. If subsurface properties change significantly signaling contamination mobilization, groundwater quality analytical parameters will be updated to account for this. Analysis of whole-rock chemistry and mineralogy will be leveraged to update the analyte list appropriately.*
- *CES proposes a 10-year alternative post-injection site care time frame and notes in the PISC and Site Closure Plan (Attachment D) that the post injection site care plan will be finalized based on the results of AoR modeling performed using the data to be collected after pre- operational testing* is complete. If, based on the updated modeling, this timeframe is insufficient, the post-injection groundwater monitoring strategy will need to be revised accordingly (e.g., to describe monitoring after year 10 post-injection).
- *Comment noted. If modeling indicates the existing site care time frame is insufficient, the post-injection groundwater modeling strategy will be updated to accommodate a time appropriate monitoring plan of action.*

- *EPA will need to review construction procedures and specifications for each of the monitoring wells prior to construction; additional information is provided in the well construction and plugging review report.*
- *CES will provide EPA with all relevant construction design, scope, and execution information prior to the commencement of monitoring well construction.*
- *The location of **ACZ1** will depend on the final site characterization evaluation and findings about the transmissive nature of any faults based on 3D seismic.*
- *The final location of ACZ1 depends on subsurface and surface site characterization information included in standard site assessment data sets, including, but not limited to, cultural surface data; 3D seismic data; well log analysis; and structural, facies, petrophysical, and dynamic models.*

EPA Evaluation of Responses: The responses above are acceptable.

2.6 CO_2 Plume and Pressure Front Tracking

CES described plans for CO_2 plume and pressure front tracking that include (1) the use of direct methods for tracking the pressure front within the injection zone [40 CFR 146.90(g)(1)] and (2) direct measurements at OBS 1 and indirect geophysical techniques to track the extent of the CO_2 plume [40 CFR 146.90(g)(2)].

2.6.1 CO_2 Plume Monitoring

CES proposes direct monitoring of the extent of the CO_2 plume will be accomplished by fluid sampling in the Second Panoche Sand in the Mendota OBS 1 well to the northeast of the injection well to help confirm predictions of CO_2 plume movement. The precise location of this well will be based on where the AoR delineation model predicts detectable pressure change within 6 months and CO_2 saturation of 10 to 20% within approximately one year.

Baseline sampling to monitor the CO_2 plume will be performed during well construction and then once prior to injection. The monitoring frequency during the injection phase will be annual; and during the post-injection phase, monitoring will be annual during years 1 through 3 and in years 5, 7, and 10. However, if CES anticipates CO_2 saturations of 10-20% at OBS 1 within the first year of injection, it would be appropriate to sample more frequently in the first one or two years in case the predictions are an underestimate or overestimate. The analytical parameters are the same as those planned for groundwater quality monitoring above the confining zone, with the additional parameter of water density.

Proposed indirect CO_2 plume monitoring activities include pulsed neutron monitoring, a 3D surface seismic survey or a combination of borehole and surface seismic, and time-lapse vertical seismic profile (VSP) survey:

- Pulsed neutron logging within the Panoche Sands will be performed in OBS 1 and the injection well (Mendota INJ 1) to monitor the formation CO_2. Following a baseline log in each well, pulsed neutron logging during the injection phase will be quarterly through year 1.5, then annually afterwards; post-injection phase logging will be performed in years 1, 3, 5, 7, and 10.

- Time-lapse VSP surveys will be performed at Mendota OBS 1 to monitor the migration of the plume over an area of about 100 to 2,000 acres. The surveys will be performed during well construction to establish a baseline, and during years 2, 3, and 4 of the injection phase. There will be no VSP monitoring during the post-injection phase.
- Surface 3D seismic surveys will be performed prior to construction to establish a baseline and in year 3

of the injection phase. Post-injection phase 3D seismic surveys will be performed during years 1, 5, and 10 after injection ceases.

The Testing and Monitoring Plan is unclear as to whether time-lapse VSP surveys or 3D surface seismic surveys (or both) are planned. This decision will need to be made prior to issuing the Class VI permit (or at least prior to authorization to inject). If CES only plans to perform time-lapse VSP, this monitoring activity will need to extend into the post-injection phase, and the imaging will need to encompass an area on the larger end of the range CES identifies in order to encompass the entire 2.2 square mile AoR.

2.6.2 Pressure Front Monitoring

Proposed direct pressure front monitoring activities include continuous pressure/temperature (P/T) monitoring and distributed temperature sensing (DTS). This monitoring will target the First, Second, and Third Panoche Sands at Mendota OBS 1 and the injection interval at the Mendota INJ 1 injection well. Following baseline measurements, continuous direct pressure front monitoring will occur throughout the injection phase and in Years 1-3 of the post-injection phase. After year 3 post-injection, annual P/T measurements will be taken (with no additional DTS).

Proposed additional pressure front monitoring will be accomplished via continuous passive seismic monitoring to detect seismic events over M1.0 within the AoR. The application states that there will be multiple target locations at a combination of borehole and seismic stations within the AoR but does not identify the specific locations.

Questions/Requests for CES:

- *Table 9 indicates that fluid sampling for CO_2 plume and pressure front tracking will be performed in OBS1. What parameters does CES propose to analyze?*
- *Please refer to Table 10 for the parameters for fluid sampling.*

EPA Evaluation of Response: This clarification addresses the question. The response is acceptable.

- *EPA will require that direct CO_2 monitoring in OBS 1 be performed more frequently than annually in the initial years of injection (i.e., through year 2) to validate modeled predictions of CO_2 plume movement.*
- *OBS 1 will be monitored on a quarterly basis during the first 1.5 years of injection. After the first 1.5 years, the sampling rate will be annual.*

EPA Evaluation of Response: The answer is not clear with respect to what happens at the 2-year mark.

Follow-up Question/Request for CES:

- Regarding the CO_2 monitoring frequency in OBS1, does shifting to annual sampling after the first 1.5 years of injection mean that the next sampling event after year 1.5 will be at 2.5 years? If so, then the required quarterly monitoring frequency does not extend through year 2 (i.e., sampling would not be performed in the final 2 quarters of the second year of injection). Please revise the Testing and Monitoring Plan to indicate that CO_2 monitoring in OBS1 will occur 3, 6, 9, 12, 15, 18, 21, and 24 months after commencement of injection, then annually thereafter.
  - Changed to quarterly monitoring for years 0 to 2 and annually from years 2 forward.

- *The spreadsheet of testing and monitoring activities identifies injection profile monitoring (Spinner) surveys in INJ1 and CO_2 analysis as direct CO_2plume monitoring activities and monitoring of injection volume in INJ_1 as a pressure front monitoring technique; however, these do not appear to be plume and pressure front monitoring techniques. Please remove them from the testing and monitoring strategy or clarify how they will be used to track the CO_2plume and pressure front in the subsurface.*

- *A spinner survey (or production logging tool) is commonly used during the injection to identify* the flow rates (or fractional rates) of specified perforation intervals. This information provides valuable results in helping to explain/monitor well behavior during the test analysis and in the subsequent simulation efforts (model calibration) for plume and pressure prediction, which will be critical to the monitoring and validation.

EPA Evaluation of Response: The response clarifies that although spinner surveys are not direct measurements of pressure or CO_2 saturation, they support overall monitoring of project performance and improved model calibration.

- *Table 9 indicates that VSP in OBS 1 will be performed in Years 2, 3, and 4 of the injection phase. EPA will require that additional VSP be performed in the later years of the injection phase to provide additional data points for the non-endangerment demonstration.*

- *Comment noted. As the site-specific data are acquired and the pressure and plume AoRs are updated subsequently, reevaluation of VSP acquisition will be reviewed after Year 4.*

EPA Evaluation of Response: The response is acceptable. EPA requests that this be included in the updated Testing and Monitoring Plan.

- This will be added to the Testing and Monitoring Plan.

- *Please clarify how the VSP and 3D seismic will work together to provide plume tracking (taking into account the capabilities and strengths of each method). In particular, it is important that each test is employed at a consistent frequency throughout the injection and post-injection phases to allow data comparisons to support the non-endangerment demonstration.*

  - *The proposed seismic methodology will be to first acquire a surface seismic 3D survey to image the horizons and faults in the study area. Modeling for the 3D VSP will then be performed to assess the impedance contrasts expected downhole and coverage map for the 3D VSP. If it is determined through modeling that the plume can be imaged with 3D VSP, then 3D VSP will be the proposed seismic method for mapping the plume post-injection, with approval from EPA.*

EPA Evaluation of Response: The response is acceptable. EPA requests that this be included in the updated Testing and Monitoring Plan.

- This will be added to the Testing and Monitoring Plan.

- *What is the planned resolution and extent of the 3D seismic surveys?*
- *The current design of the 3D seismic survey will cover the extents of the plume at 100 years at full fold and full azimuth (as allowed by infrastructure constraints). The inline and crossline bin spacing will be less than 100 ft, to ensure that faults and reflecting horizons are properly imaged.*

EPA Evaluation of Response: The response is acceptable. EPA requests that this be included in the updated Testing and Monitoring Plan.

- *There are numerous inconsistencies between the tables in Attachments C and E and the spreadsheet of testing and monitoring activities (e.g., in the frequencies at which various testing and monitoring activities are to be performed). Please revise the spreadsheet or the plans as needed or resolve the discrepancies.*
- *Tables in Attachment C and E will be updated accordingly.*

EPA Evaluation of Response: The response is acceptable. EPA will confirm the revisions when the updated Testing and Monitoring Plan and PISC and Site Closure Plan are submitted.

- *Please describe the proposed passive seismic monitoring network (i.e., the number and location of monitoring stations). Are any state or federally operated (e.g., USGS) seismic monitoring stations nearby that will inform seismic monitoring of the CES project?*
- *An induced seismicity monitoring (ISM) surface geophone network and a distributed acoustic sensing (DAS) fiber-optic cable will be installed permanently downhole in monitoring wells OBS 1 and ACZ1 and will be used to locate microseismic events with accuracy in real time. As a part of standard operating procedure, these data will also be integrated with information from nearby state and federally operated seismic monitoring stations to provide a safety net. The combined high-order governmental, surface ISM, and downhole DAS passive seismic monitoring network will quickly and accurately locate seismic events of interest in and around the AoR. Currently, there are governmental seismic monitoring stations but they are more than 10 miles away from the Mendota site and thus would provide only limited information.*

EPA Evaluation of Response: The response is acceptable.

- *The spreadsheet of testing and monitoring activities indicates that continuous DTS monitoring will be performed for pressure front tracking in OBS 1 for the first 3 years of the post-injection site care timeframe, but this is not included in Table 6 of the PISC and Site Closure Plan. Please clarify the discrepancy.*
  - OBS1 was added to the DTS row of **Error! Reference source not found** of the PISC and Site Closure Plan.

EPA Evaluation of Response: It is assumed this response refers to Table 6. EPA will confirm the revision when the updated PISC and Site Closure Plan is submitted.

- *Please also explain why additional DTS monitoring is not proposed beyond year 3 post-injection, or what data trends may indicate that additional temperature monitoring is not warranted, particularly in consideration of collecting post-injection phase data to support the non- endangerment demonstration.*
- *DTS monitoring has been changed to 10-year monitoring, in line with the pulsed neutron*

logging plan. DTS monitoring subsurface equipment will still be in place once the initial post-injection time is completed and thus may continue to be monitored if so required.

EPA Evaluation of Response: The response is acceptable. EPA will confirm the revisions when the updated Testing and Monitoring Plan is submitted.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *Updated modeling (numerical multiphase transport modeling and geochemical modeling) to demonstrate the adequacy of the proposed 10-year alternative post injection site care time frame will be conducted in the pre-operational testing phase. If this timeframe is insufficient based on the updated modeling, the post-injection plume and pressure front tracking strategy will need to be revised accordingly.*
- *As the modeling work is updated with the site-specific data, the10-year alternative post-injection site-care timeframe will be reevaluated and modified if needed. The post-injection plume and pressure front tracking strategy will be updated according to the revised modeling results.*

EPA Evaluation of Response: The response is acceptable.

- *The maps in the application on which monitoring locations are overlain (e.g., Figures 3 through 7 of the Testing and Monitoring Plan) are based on the pre-construction AoR modeling results; any changes to the predicted position of the CO_2 plume and pressure front based on the AoR modeling evaluation may necessitate reexamination of the well locations and revision of these maps and cross sections.*
- *As the site-specific data are acquired and the pressure and plume AoRs are updated subsequently, reevaluation of the well locations will be done according to the changes in the pressure and plume front.*

EPA Evaluation of Response: The response is acceptable.

- *Mendota OBS 1 is currently described as targeting the Second Panoche Sand; if the Fourth Panoche (the alternate injection zone) is selected, this monitoring well should penetrate and be screened in that sand. Likewise, pressure/temperature monitoring in that zone would be necessary as well.*
  - Current strategies target the Second Panoche Sandstone as the primary target and the First Panoche Sandstone stratigraphically above it as the secondary target. If the primary and secondary targets prove untenable, then the Mendota OBS 1 well would be extended through the Third Panoche and the Fourth Panoche, which comprise the tertiary CO_2 injection zone option. Using the Fourth Panoche as an injection interval is unlikely at this time.

EPA Evaluation of Response: ***The response is acceptable.***

- *CES will need to clarify which seismic methods will be used (i.e., VSP and/or surface seismic survey) prior to authorization of injection. If only VSP is planned, the imaging area will need to be at a range closer to the high end of the range (i.e., 2,000 acres) to encompass the entire AoR.*
- *The proposed seismic methodology will be to first acquire a surface seismic 3D survey to image the*

horizons and faults in the study area. Modeling for the 3D VSP will then be performed to assess the impedance contrasts expected downhole and coverage map for the 3D VSP. If it is determined through modeling that the plume can be imaged with 3D VSP, then 3D VSP will be the proposed seismic method for mapping the plume post-injection, with approval from EPA.

EPA Evaluation of Response: The response is acceptable.

- *The QASP may need to be updated when final determinations are made based on pre-operational testing about specific testing and monitoring activities (e.g., related to plume and pressure front tracking)*

- *The QASP will be updated accordingly based upon pre-operational testing and monitoring activities.*

EPA Evaluation of Response: The response is acceptable.

2.7 Air/Soil or Other Testing and Monitoring

Based on the currently available information about the geologic setting (i.e., the depth of the injection formations and the lack of evidence for the presence of transmissive faults or fractures), surface air and/or soil gas monitoring are not needed to detect movement of fluid that could endanger USDWs within the AoR.

Considerations based on the results of Pre-Operational Testing/Modeling Updates:

- *If, based on the results of planned pre-operational testing, uncertainties about the geologic setting are identified, the need for air and/or soil gas monitoring or other monitoring will be reconsidered.*

- *Air and/or soil gas monitoring will be reviewed based upon the results of the pre-operational testing and confirmation of geological uncertainties.*

EPA Evaluation of Response: The response is acceptable.

2.8 Quality Assurance Procedures

EPA evaluated the Quality Assurance Surveillance Plan (QASP) submitted with the permit application to verify that all of the testing activities, analytes, etc., included in the QASP are consistent with planned injection and post-injection phase testing and monitoring. The QASP described sampling methods; sample handling and custody; analytical methods; quality control; instrument/equipment testing, inspection, and maintenance; data management, e.g., recordkeeping and tracking practices; and data review, verification, and validation procedures.

Most monitoring activities listed in Attachment C: Testing and Monitoring Plan were addressed in the QASP. The exceptions are two MITs: temperature logging and oxygen activation (OA) logging. The procedures for these MITs should be described in the QASP as they are not sufficiently detailed and described in the Testing & Monitoring Plan.

All of the monitoring activities listed in Attachment E: Post-Injection Site Care and Site Closure Plan were addressed in the QASP.

Questions/Requests for CES:

- *For completeness, please revise the QASP to include the details of the temperature and oxygen activation procedures to demonstrate external MI (including specific calibration procedures for OA logging).*

- CES will develop specific procedures for each well after drilling and logging are completed. For each individual well with temperature and OA logging, there will be specific requirements and instructions for pre- and post-calibrations, normalizations, and interpretations of MI that take core, open- and cased-hole logs, and any other vital information into consideration. These specific procedures allow the operations to be tailored to include exact depths, intervals, casing sizes, wellbore fluids, and environmental aspects, which allow for the best MI analysis possible.

EPA Evaluation of Response: The response is acceptable. EPA will review the procedures when the updated QASP is submitted.

APPENDIX A: WELL SCHEMATICS

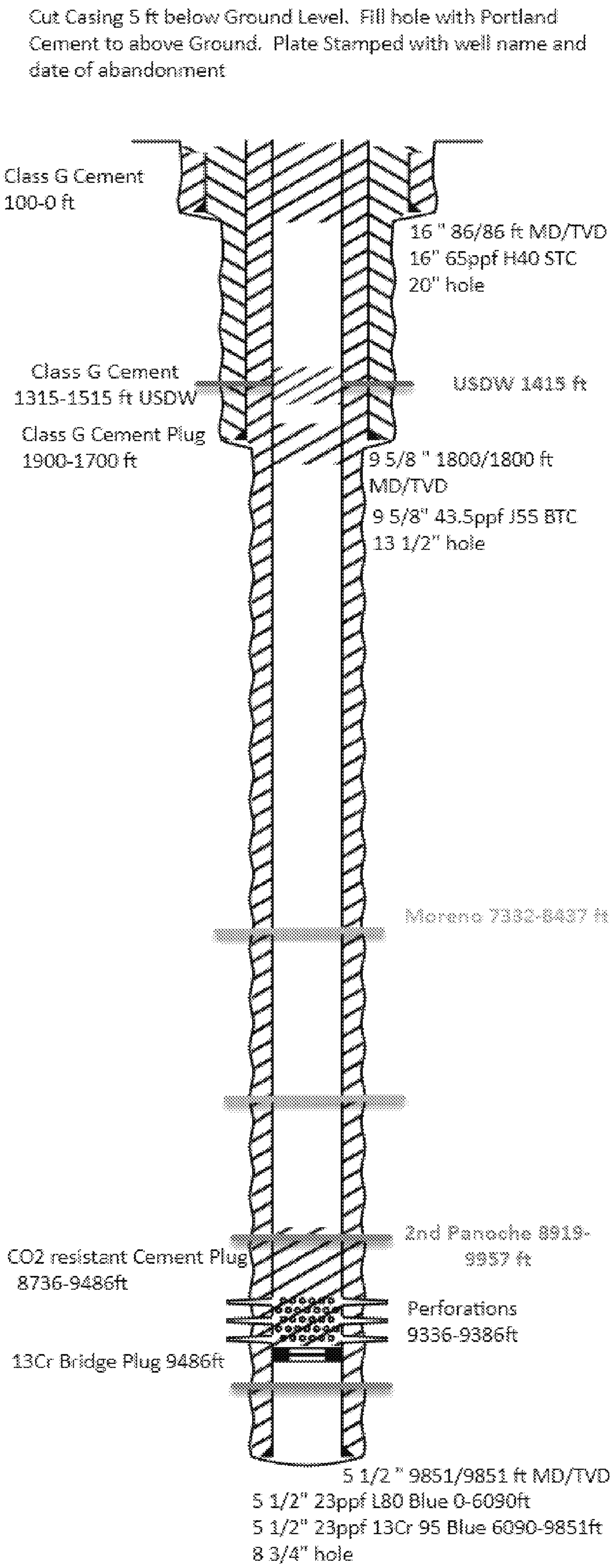


Fig. A-1. Mendota monitor-1 plug schematic.

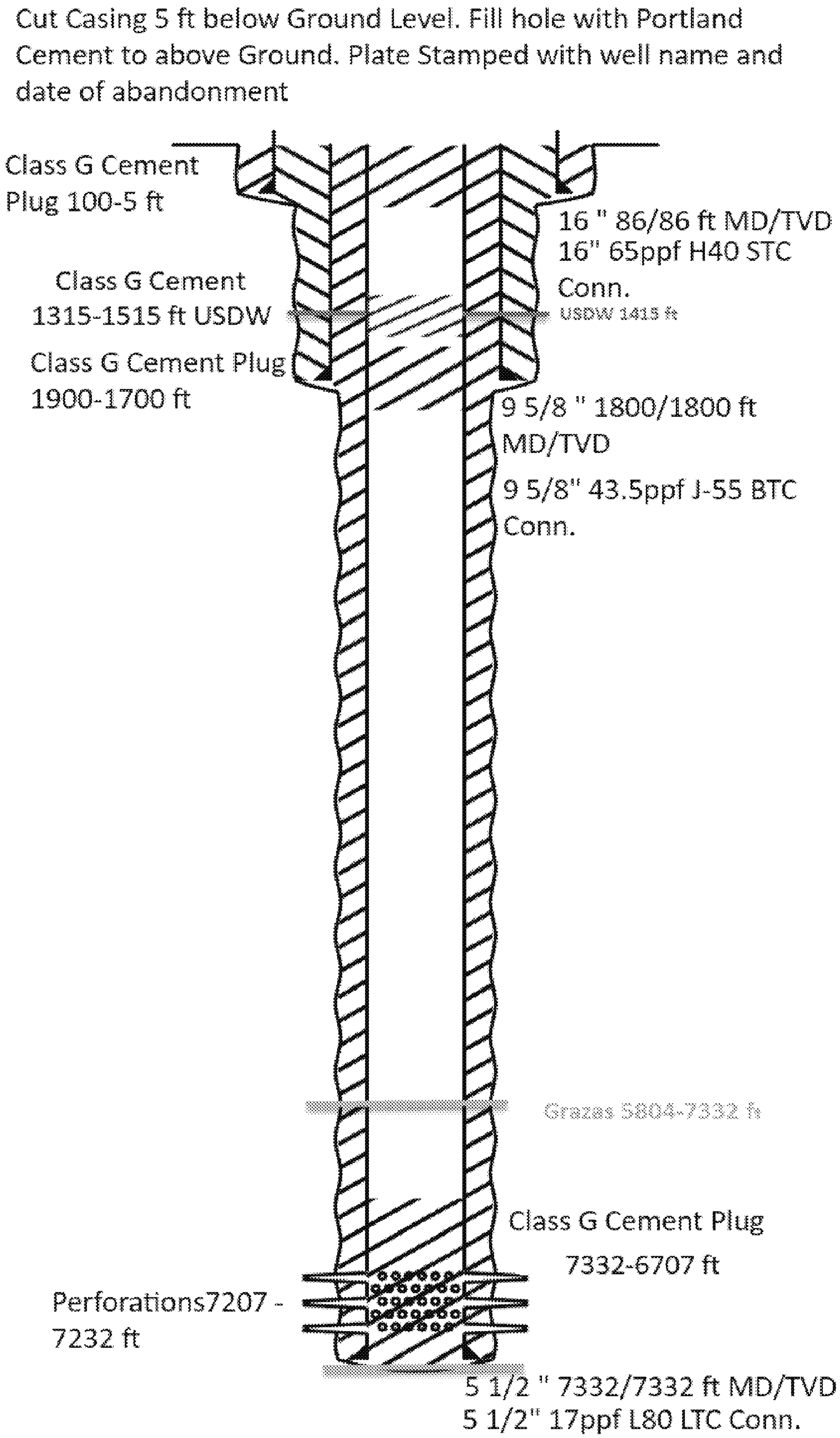


Figure A-2. Mendota AZ-1 plug schematic.

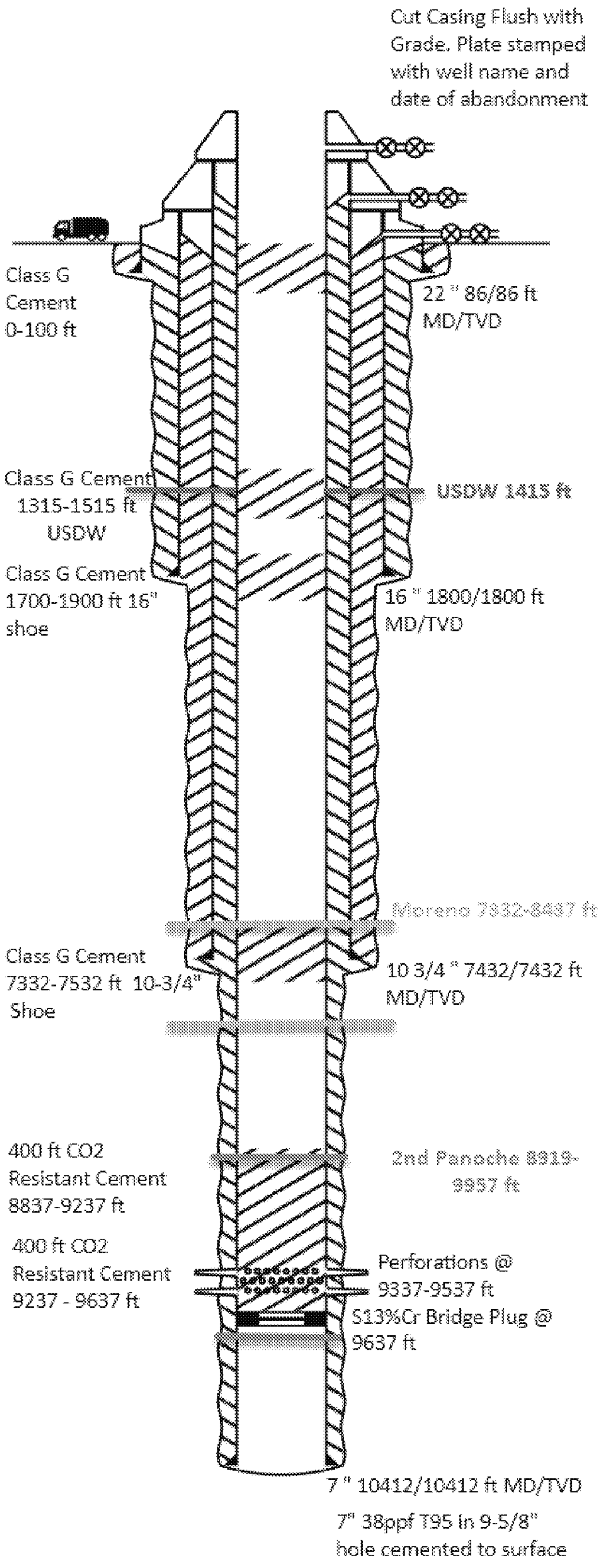


Figure A-3. Mendota injection plug schematic.

APPENDIX B:

UPADATED EMERGENCY AND REMEDIAL RESPONSE PLAN

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN 40 CFR 146.94(a)
CLEAN ENERGY SYSTEMS MENDOTA

1. Facility Information

Facility name:	CLEAN ENERGY SYSTEMS MENDOTA MENDOTA_INJ_1
Facility contact:	Rebecca Hollis 400 Guillen Pkwy, Mendota, CA 93640 Office: 916-638-7967
Well location:	MENDOTA, FRESNO COUNTY CA LAT/LONG COORDINATES (36.75585015/-120.36440423)

This Emergency and Remedial Response Plan (ERRP) describes actions that Clean Energy Systems shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If Clean Energy Systems obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, Clean Energy Systems must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: Clean Energy Systems will immediately cease injection. However, in some circumstances, Clean Energy Systems will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

This attachment is one of the several documents listed below that was prepared by Schlumberger and delivered to Clean Energy Systems. These documents were prepared to support the Clean Energy Systems preconstruction application to the EPA.

- (Schlumberger, Attachment A: Summary of Requirements Class VI Operating, 2020)
- (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020)
- (Schlumberger, Attachment C: Testing and Monitoring Plan, 2020)
- (Schlumberger, Attachment D: Injection Well Plugging Plan, 2020)

- (Schlumberger, Attachment E: Post-Injection Site Care and Site Closure Plan, 2020)
- (Schlumberger, Attachment F: Emergency and Remedial Response Plan, 2020)
- (Schlumberger, Attachment G: Construction Details Clean Energy Systems Mendota, 2020)
- (Schlumberger, Attachment H: Financial Assurance Demonstration, 2020)
- (Schlumberger, Class VI Permit Application Narrative, 2020)
- (Schlumberger Quality Assurance and Surveillance Plan, 2020)

Contents

1.1 Acronyms and Abbreviations

*: Denotes a Mark of Schlumberger

AoR: Area of review

BFS: Base of fresh water

BGS: Below ground surface

CCS: Carbon capture and storage

CEMA: California Emergency Management Agency

CES: Clean Energy Systems

CNE: Carbon negative energy

DFN: Discrete fracture network

DST: Drillstem test

DT: Compressional slowness

DTS: Distributed temperature sensing

EPA: Environmental Protection Agency

FMI: Formation microimager

GRFS: Gaussian random function simulation

GR: Gamma ray

GS: Geological sequestration

KH: Permeability thickness

KINT: Permeability

Mendota_INJ_1: Proposed CO_2 injection well

MIT: Mechanical integrity test

MWD: Measurement while drilling

NPHI: Neutron porosity

PISC: Post-injection site care

PHIT: Total porosity

PIGE: Effective porosity

RHOB: Bulk density

Rwa: Formation water resistivity

SGR: Shale gouge ratio

Shmax: maximum horizontal stress

Shmin: minimum horizontal stress

SP: Spontaneous potential

USDW: Underground sources of drinking water

VCL: Volume clay

VSP: Vertical seismic profile

Vp/Vs: Compressional to shear velocity ratio

XRD: X-ray diffraction analysis

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2. Local Resources and Infrastructure

Based upon EPA's Technical Evaluation Comments and Information Request #2 for Underground Injection Control (UIC) Permit Application Class VI Pre-Construction Permit Application No. R9UIC-CA6-FY20-1 dated October 1, 2020, the yellow highlighted sections have been incorporated as per EPA's request.

Resources in the vicinity of the Clean Energy Systems Mendota that may be affected as a result of an emergency event at the project site include:

- Underground sources of drinking water, or USDW's and water wells within the AoR. There are approximately 67 water supply wells, monitoring wells, water wells and abandoned wells within the AoR (red polygon Figure 1). A map displaying the locations of these wells can be found in the (CLASS VI PERMIT APPLICATION NARRATIVE 40 CFR 146.82(a) Clean Energy Systems Mendota, 2019). The locations of these wells as shown on the mapwere slightly displaced because the wells were originally reported in a legal land description format; therefore, the wells all plot in the middle of a section and apper to line up in an organized grid pattern (California Department of Water Resources, n.d.). In future phases of this project, accurate locations of these water wells will be provided. The deepest USDW is the Santa Margarita formation at depth of approximately 1,400 ft. The San Joaquin River flows north south and is 0.6 miles due east of the site. The northern boundary of the Mendota Wildlife Area is 1.7 miles to the south. Managed by the California Department of Fish and Wildlife. The Mendota Wildlife Area is approximately 11,800 acres consisting of flatlands and floodplain.

Infrastructure in the vicinity of the Clean Energy Systems Mendota that that may be affected as a result of an emergency at the project site include:

- The town of Mendota, CA is west of the site. Mendota is a town in Fresno County. The population was 11,014 at the 2010 U.S. Census. It covers 3.3 square miles and has approximately 2,750 households. The nearest residence to the site is 0.5 miles west and outside the AoR. Mendota is located 8.5 miles south-southeast of Firebaugh, at an elevation of 174 feet. Between the site and the town are several businesses, including Gonzales Transport and airstrip (1,500') west. There is also the King Kool cold storage facility and Oro Loma Ranch/Ruby Fresh, a pomegranate marketing firm. Mendota High School is 0.7 miles south-west. The North Star solar facility borders on the north of the site and is a 61-megawatt facility is located on 626 acres.

Resources and infrastructure addressed in this plan are shown in Figure 1.

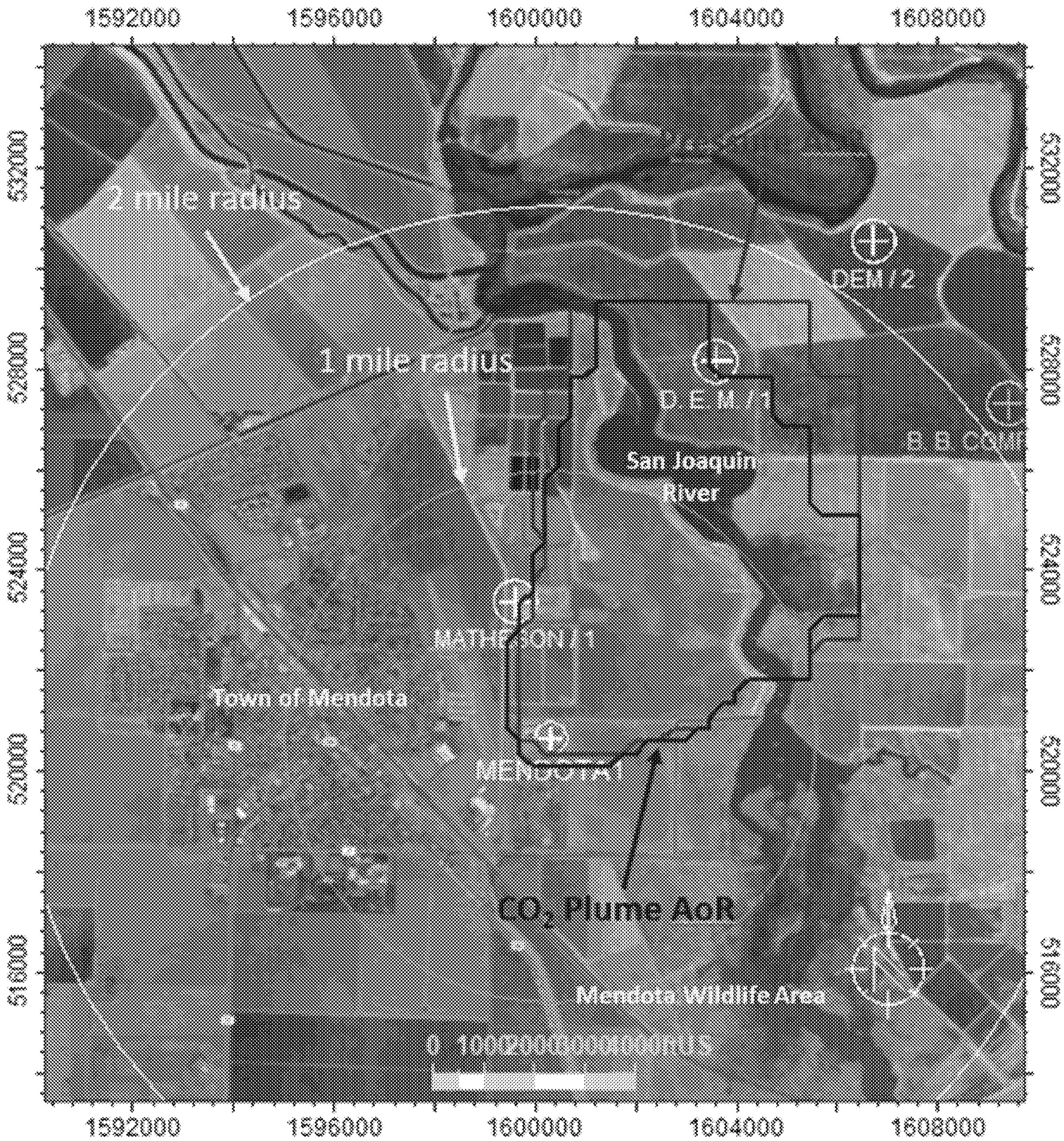

Figure 1. Map of the site resources and infrastructure

3. Potential Risk Scenarios

The following events related to the Clean Energy Systems Mendota that could potentially result in an emergency response:

- Over-pressurized fluid (blowout) during well construction;
- Injection or monitoring (verification) well integrity failure;

- Injection well monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, lightning strike);
- Fluid (e.g. brine) leakage to a USDW;
- CO_2 leakage to USDW or to land surface; or
- Induced seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

4. Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

4.1 Over-pressurized fluid (blowout) during well construction

This event could occur during well drilling if a pocket of high-pressure gas or fluid is encountered resulting in a sudden release:

- Cease operations:
  - Loss of well control due to inadequate barrier in place or human error.
  - Drilling into an over-pressured formation or improper well control initiated during maintenance or workover process.

Severity: Catastophic

Timing of event: Pre-injection and injection.

Avoidance measures: Monitoring and training.

Detection methods: Pressure monitoring, injection rate decreasing, and fluid leaks.

Potential response actions:

- Cease drilling operations: loss of drilling fluid due to lost circulation and/or drilling into an over-pressured formation
- Close flow valve (blowout preventer) if pressures and flows permit, at a minimum vent to a controlled area.
- Regain pressure control by restoring fluid levels in the wellbore with appropriate density mud, restriction of flow through choke or both.
- For a Major or Serious emergency:
    - Initiate well control procedures (see well plan).
    - Alert local fire and police and UIC Program Director immediately.
- For a Minor emergency:
    - Regain pressure control by restoring fluid levels in the wellbore with appropriate density mud, restriction of flow through choke or both.
    - Determine cause of event and initiate remediation procedures.
    - Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).

Response personnel: Site operator, well engineer, and project manager.

Equipment: Pressure control equipment, pumping equipment and rig.

4.2 Well Integrity Failure

Integrity loss of the injection well and/or verification well may endanger USDWs. Examples of well integrity failure may include scenarios related to wellhead pressure, annulus pressure, mechanical integrity, and failure of monitoring equipment. For further details please refer to Risk Register scenario numbers 2a, 2b, and 2c.

Integrity loss may have occurred if the following events occur:

Scenarios:

1. Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
2. Annulus pressure indicates a loss of external or internal well containment.
3. Mechanical integrity test results identify a loss of mechanical integrity.

- Limit access to wellhead to authorized personnel only.
- Automatic shutdown devices are activated:

- Wellhead or downhole pressures exceeds the specified shutdown pressure specified in the permit.
- Annulus pressure and/or fluid volumes indicate a loss of external or internal well containment.
- Pursuant to 40 CFR 146.91(c)(3), Clean Energy Systems must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Light, serious, or catastrophic.

Timing of event: Injection/monitoring.

Avoidance measures: Well maintenance, injection within permitted limits, and monitoring.

Detection methods: Pressure monitoring and mechanical integrity tests.

Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (verified loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
  - Initiate immediate shutdown plan.
  - Shut in well (close flow valve). After verifying pressures, with analog gauges, to confirm no damage will occur to the well or USDW.
  - Monitor well pressure, temperature, and acoustics to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).
  - Vent fluids, if necessary, from wellhead in order to maintain acceptable pressures at surface and downhole in order not to damage the wellhead or casing.
  - Communicate with CES personnel and local authorities to initiate evacuation plans, as necessary.
  - If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director).
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.

   - Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).
   - If there is damage to the wellhead, repair the damage and conduct a survey to ensure wellhead leakage has ceased.
   - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
   - Review downhole, wellhead, and annulus pressure data.
   - Isolate the nearby area, if needed; establish a safe distance and perimeter using a hand-held air-quality monitor.
   - Perform a well log/MIT to detect CO2 movement outside of the casing.

- For a Minor emergency (downhole and surface sensor/monitoring equipment failure, procedural maintenance error or plant issue) :
   - Initiate immediate shutdown plan.
   - Monitor well pressure, temperature, and acoustics to verify integrity loss and determine the cause and extent of failure; use analog gauges to identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).
   - If a shut off is triggered by mechanical or electrical malfunctions without endangering a USDW, repair faulty components.
   - Review downhole, wellhead, and annulus pressure data.
   - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
   - If contamination is detected or well integrity has been determined to have occurred, then situation becomes a Major or Serious emergency. Refer to Major or Serious solutions above.

Response personnel: Site operator, well engineer, and project manager.

Equipment: Workover rig, wireline, slickline, and well control equipment.

4.3 Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead/downhole pressure, temperature, and/or acoustics may indicate a problem with the injection well that could endanger USDWs. Additionally, equipment failures (sensor, computer, cabling, etc) and damage to the wellhead could endanger the USDW. For further details please refer to Risk Register scenario numbers 3a and 3b.

Severity: Light to catastrophic.

Timing of event: Injection/monitoring.

Avoidance measures: Well maintenance, injection within permitted limits, and monitoring.

Detection methods: Equipment monitoring.

Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- Limit access to wellhead to authorized personnel only.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48hrs) and/or well reentry to fix problem):
    - Initiate immediate shutdown plan.
    - Monitor well pressure, temperature, and acoustics to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).
    - Review downhole and wellhead pressure, temperature & acoustic data.
    - Evaluate pressures and conditions via analog gauges to determine no damage to wellbore, wellhead or USDW will occur.
    - Shut in well (close flow valve or allow packer fluid into reservoir, fill hole).
    - Vent fluids from wellbore & surface facilities.
    - Communicate with CES personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).
    - If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - Isolate the nearby area, if needed; establish a safe distance and perimeter using a hand-held air-quality monitor.
    - Perform a well log/MIT to detect CO2 movement outside of the casing.
- For a Minor emergency: (sensor or monitoring failure that does not require shutdown of well to repair)
    - Monitor well pressure, temperature, and acoustics to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).

- Conduct assessment to determine whether there has been a loss of mechanical integrity.
- If there has been a loss of mechanical integrity, continue shutdown plan and refer to Major or Serious emergency guidelines.
- Reset automatic shutdown devices.
- Evaluate the cause of the failure, and mitigate if necessary (i.e., repair equipment).
- Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

Response personnel: Site operator, well engineer, technician(s) for monitoring equipment and project manager.

Equipment: Workover rig, wireline, and backup monitoring equipment.

4.4 Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW. This scenario will encompass any evidence of CO2 or fluid movement out of the injection zone (i.e., not necessarily to a USDW) to address unanticipated events associated with faults or other pathways; any potential USDW endangerment/unacceptable changes in water quality; and CO2 leakage to the land surface. For further details please refer to Risk Register scenario numbers 4a and 4b.

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW. To better protect the USDW and to have an early warning system for USDW impact, it is important to monitor out of zone CO_2 migration above the stroarge complex. This scenario will encompass any evidence of CO_2 or fluid movement out of the injection zone (i.e., not necessarily to a USDW) to address unanticipated events associated with faults or other pathways; any potential USDW endangerment/unacceptable changes in water quality; and CO_2 leakage to the land surface. The technology that is planned to be used to identify and quantify the severity of a potential brine or CO_2 leakage to USDW is described in the (Schlumberger, Attachment C: Testing and Monitoring Plan, 2020).

Severity: Catastophic

Timing of event: Pre-injection, injection, and/or post-injection phases.

Avoidance measures: Well maintenance, injection within permitted limits, and monitoring.

Detection methods: Fluid sampling and atmospheric and subsurface monitoring.

Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).

- Determine the severity of the event, based on the information available, within 24 hours of notification.
- Limit access to wellhead to authorized personnel only.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO2, or "pump and treat" to aerate CO2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by Clean Energy Systems and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
    - If there is a well integrity issue specific steps will be taken to identify the location of the failure/leak, affect repairs, and demonstrate mechanical intergrity.
    - If the leak posses a risk to air quality the nearby area will be isolated and a safe distance and perimeter will be established a using a hand-held air-quality monitor.

Response personnel: Site operator, groundwater consultant, and project manager.

Equipment: Groundwater remediation equipment.

4.5 Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities. For further details please refer to Risk Register scenario number 5a.

Severity: Catastophic

Timing of event: Pre-injection, injection, and/or post-injection phases.

Avoidance measures: Meterological monitoring.

Detection methods: Microseismic monitoring and meterological monitoring.

If a natural disaster occurs that affects normal operation of the injection well, perform the following:

Response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- Limit access to wellhead to authorized personnel only.
- For a Major or Serious emergency:
    - Initiate immediate shutdown plan. Shut in well (close flow valve).
    - Vent CO2 from surface facilities if appropriate.
    - Communicate with CES personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).
    - Determine if any leaks to ground water or surface water occurred.
    - If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate immediate shutdown plan.
    - If there has not been a loss of mechanical integrity, initiate gradual shutdown.
    - Shut in well (close flow valve).
    - Vent CO2 from surface facilities if appropriate.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate

remedial actions to repair damage to the well (in consultation with the UIC Program Director).

Response personnel: Site operator and groundwater consultant.

Equipment: To be determined immediately following natural disaster.

4.6 Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event at all. Simulations show extremely small pressure increase produced by the planned injection into the Second Panoche formation. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a 0.5-mile radius of the injection well.

To monitor the area for seismicity, an optical cable will be installed in the Above Confining Zone monitor well (Mendota_ACZ_1) with Digital Acoustic (DAS). The DAS fiber cable will monitor continuously and be recorded by a surface recording system. The recording system will be programed to identify induced seismic events in real time and is programed to automatically send alerts to site safety personnel.

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in *Table 2*. The table corresponds each level of operating state with the threshold conditions and operational response actions. For further details please refer to Risk Register scenario numbers 6a, 6b, 6c, 6d and 6e.

Severity: Light, major, or Catastophic

Timing of event: Pre-injection, injection, and/or post-injection phases.

Avoidance measures: Injection within permitted limits.

Detection methods: Microseismic monitoring.

Potential response actions:

Table 2. Seismic monitoring system, for seismic events > M1.0 with an epicenter within a 0.5-mile radius of the injection well.

Operating State	**Threshold Condition[1,2]**	**Response Action[3]**
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event for reporting to EPA in semiannual reports.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the well if it is determined to be appropriate. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 4. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls within or near the extents of the plume, use the microseismic, geomechanics and facies data to estimate potential impact to USDWs. Perform a pressure fall-off test to determine if the storage complex has been compromised by the seismic event. 5. Document the event for reporting to EPA in semiannual reports.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the well if it is determined to be appropriate. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls within or near the extents of the plume, use the microseismic, geomechanics and facies data to estimate potential impact to USDWs. Perform a pressure fall-off test to determine if the storage complex has been compromised by the seismic event. 5. Report findings to the UIC Program Director and issue corrective actions. 6. Document the event for reporting to EPA in semiannual reports.

[1] Specified magnitudes refer to magnitudes determined by local Clean Energy Systems or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual shutdown of the well if it is determined to be appropriate. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 4. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 5. Determine if leaks to ground water or surface water or a CO_2 leak to the surface occurred. 6. If a CO_2 leak or USDW contamination/endangerment is detected: a. Notify the UIC Program Director within 24 hours of the determination and implement appropriate remedial actions in consultations with the Director. 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls within or near the extents of the plume, use the microseismic, geomechanics and facies data to estimate potential impact to USDWs. Perform a pressure fall-off test to determine if the storage complex has been compromised by the seismic event. 8. Report findings to the UIC Program Director and issue corrective actions. 9. Document the event for reporting to EPA in semiannual reports.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate immediate shutdown plan. 2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Seismic event >M3.5	3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 4. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 5. Determine if leaks to ground water or surface water or a CO_2 leak to the surface occurred. 6. If a CO_2 leak or USDW contamination/endangerment is detected: a. Notify the UIC Program Director within 24 hours of the determination and implement appropriate remedial actions in consultations with the Director. 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls within or near the extents of the plume, use the microseismic, geomechanics and facies data to estimate potential impact to USDWs. Perform a pressure fall-off test to determine if the storage complex has been compromised by the seismic event. 8. Report findings to the UIC Program Director and issue corrective actions. 9. Document the event for reporting to EPA in semiannual reports.

Response personnel: Site operator and microseismic provider.

Equipment: Microseismic monitoring and falloff test.

5. Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Emergency Coordinator - Control Room technician on Duty: 559-655-4923
2. Plant Safety Manager - Clint Cooper: Off: (559) 655-3947, 24 hr: 559-916-2139
3. Alt Facility Emergency Coord.: Arnold Gonzales: Office: (559) 655-4921 x12 Mobile: (559) 916-2142
4. Plant Manager

A site-specific emergency contact list will be developed and maintained during the life of the project. Clean Energy Systems will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	**Phone Number**
Local police	911
Mendota Fire Department	911
Ambulance/Paramedics	911
Fresno Community Regional Medical Center	24 hr 559-459-6000
Poison Control Center	800-342-9293
California Office of Emergency Services	24 hr 800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Environmental services contractor - Schlumberger	661-864-4700
UIC Program Director	Not yet assigned
EPA National Response Center (24 hours)	800-424-8802
State geological survey	916-322-1080

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, Clean Energy Systems shall be responsible for its procurement.

6. Emergency Communications Plan

Clean Energy Systems will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

Clean Energy Systems will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), Clean Energy Systems will provide periodic updates on the progress of the response action(s).

Clean Energy Systems will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

7. Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) reevaluation.
- Within 30 days, or other time prescribed by the EPA Director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, Clean Energy Systems will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within 30 days, or other time prescribed by the EPA Director, following an event that initiates the ERRP review procedure.

8. Staff Training and Exercise Procedures

CES will integrate the ERRP into the storage site specific standard operating procedures and training program.

- Periodic training will be provided, not less than annually

- Training will be provided to well operators, plant safety and environmental personnel, the plant manager, plant superintendent, and corporate communications. The training plan will document that the above listed personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ERRP.

9. References

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Schlumberger Quality Assurance and Surveillance Plan. (2020). *Quality Assurance and Surveillance Plan.*

Schlumberger, Attachment A: Summary of Requirements Class VI Operating. (2020). *Attachment A: Summary of Requirements Class VI Operating and Reporting Conditions.*

Schlumberger, Attachment B: Area of Review and Corrective Action Plan. (2020). *Attachment B: Area of Review and Corrective Action Plan 40 CFR 146.84(b) Clean Energy Systems Mendota.*

Schlumberger, Attachment C: Testing and Monitoring Plan. (2020). *Attachment C: Testing and Monitoring Plan 40 CFR 146.90 Clean Energy Systems Mendota.*

Schlumberger, Attachment D: Injection Well Plugging Plan. (2020). *Attachment D: Injection Well Plugging Plan 40 CFR 146.92(B) Clean Energy Systems Mendota.*

Schlumberger, Attachment E: Post-Injection Site Care and Site Closure Plan. (2020). *Attachment E: Post-Injection Site Care and Site Closure Plan 40 CFR 146.93(A) Clean Energy Systems Mendota.*

Schlumberger, Attachment F: Emergency and Remedial Response Plan. (2020). *Attachment F: Emergency and Remedial Response Plan 40 CFR 146.94(A) Clean energy Systems Mendota.*

Schlumberger, Attachment G: Construction Details Clean Energy Systems Mendota. (2020). *Attachment G: Construction Details Clean Energy Systems Mendota.*

Schlumberger, Attachment H: Financial Assurance Demonstration. (2020). *Attachment H: Financial Assurance Demonstration 40 CFR 146.85 Clean Energy Systems Mendota.*

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